Appendix 9.6

BART Analysis for Westar Energy - Gordon Evans Unit 2 and Jeffrey Units 1 and 2 (including May 2009 addendum for GEEC)

CALPUFF BART MODELING PROTOCOL ▪ WESTAR ENERGY
HUTCHINSON, GORDON EVANS, JEFFREY, & LAWRENCE ENERGY CENTERS

VERSION 0

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1. INTRODUCTION

1.1 BACKGROUND

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are listed as one of the 26 listed source categories in the guidance.

A BART-eligible source is not automatically subject to BART. Rather, BART-eligible sources are subject-to-BART if the sources are "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that sources are reasonably anticipated to cause or contribute to visibility impairment if the visibility impacts from a source are greater than 0.5 deciviews (dv) when compared against a natural background.

Air quality modeling is the tool that is used to determine a source's visibility impacts. States have the authority to exempt certain BART-eligible sources from installing BART controls if the results of the modeling demonstrate that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. Further, states also have the authority to define the modeling procedures for conducting modeling related to making BART determinations.

To promote consistency between states in the development of BART modeling protocols and to harmonize the approaches between adjacent RPOs, CENRAP developed *BART Modeling Guidelines* (December 15, 2005). The intent of the guidelines is to assist CENRAP states and source operators in the development of statewide and source-specific modeling protocols.

1.2 OBJECTIVE

The objective of this document is to provide a protocol summarizing the modeling methods and procedures that Westar Energy (Westar) will follow as we evaluate whether BART applies to any of our BART-eligible sources. Westar will use the modeling methods and procedures to determine if our BART-eligible sources can reasonably be anticipated to cause or contribute to visibility impairment in a Class I area, and are thus subject to BART. We are proposing to consider a source subject to BART if the 98th percentile of the visibility impacts predicted by the model are above EPA's recommended visibility contribution threshold of 0.5 Δdv.

1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS

Westar has identified the following sources that meet the three criteria for being BART-eligible sources:

- ▲ Hutchinson Energy Center (HEC) – Boiler Unit 4
- ▲ Gordon Evans Energy Center (GEEC)– Boiler Unit 2
- ▲ Jeffrey Energy Center (JEC) – Boiler Units 1 and 2
- ▲ Lawrence Energy Center (LEC) – Boiler Unit 5

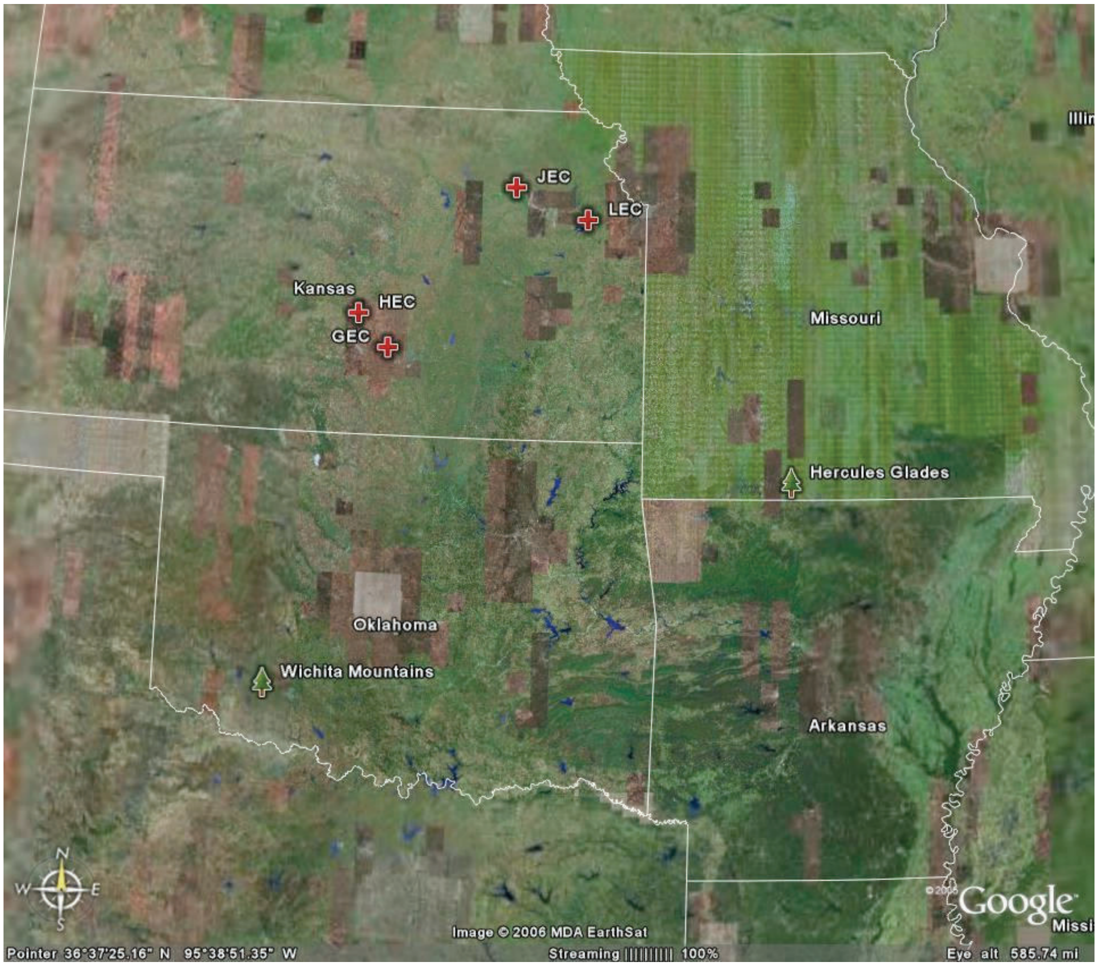
Table 1-1 provides a summary of the distances from each of our facilities with BART-eligible sources to nearby Class I areas.

TABLE 1-1. DISTANCE TO CLASS I AREAS

	Distance to Class I Area (km)			
Energy Center	**Badlands National Park**	**Wind Cave National Park**	**Hercules-Glades Wilderness**	**Wichita Mountains**
GEEC	781.48	812.69	423.51	360.36
HEC	737.12	767.48	463.08	384.36
JEC	723.64	775.72	403.08	560.08
LEC	797.14	851.57	331.64	569.00

In order to determine whether the BART eligible sources listed above are subject to BART, the visibility impacts in the two Class I areas that are within 600 km of the sources will be determined. The Class I areas within 600 km include Hercules-Glades Wilderness and Wichita Mountains. Figure 1-1 provides a plot of the location of the facilities listed above with respect to the Hercules Glades Wilderness and Wichita Mountains.

FIGURE 1-1. LOCATION OF WESTAR FACILITIES WITH BART-ELIGIBLE SOURCES AND NEARBY CLASS I AREAS



2. CALPUFF MODEL SYSTEM

The main components of the CALPUFF modeling system are CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields such as wind and temperature. CALPUFF simulates the non-steady state transport, dispersion, and chemical transformation of air pollutants emitted from a source in "puffs". CALPUFF calculates hourly concentrations of visibility affecting pollutants at each specified receptor in a modeling domain. CALPOST is the post-processor for CALPUFF, and CALPOST computes visibility impacts from a source based on the visibility affecting pollutant concentrations that were produced by CALPUFF.

2.1 MODEL VERSIONS

Earth Tech, Inc. is the primary developer of the CALPUFF modeling system and all related programs. The versions of the CALPUFF modeling system programs that will be used for our modeling are listed in Table 2-1. Table 2-1 also compares the program versions that will be used to model Westar's sources with the program versions recommended by CENRAP. Note that some of the program versions are not the same as the program versions recommended by CENRAP. The program versions are different due to the fact that several of the program versions recommended by CENRAP are incompatible with each other as published. Specifically, the MM5 data extraction program (CALMM5) Version 2.4 is not compatible with CALMET Version 5.53a. CALMM5 Version 2.4 is compatible with a newer version of CALMET, Version 5.551. Note that meteorological data that is generated with CALMET Version 5.551 is not compatible with CALPUFF Version 5.711a. CALMET Version 5.551 is compatible with CALPUFF Version 5.727. In short, alternate program versions are required in order to accommodate the MM5 data extraction program version, so Westar will use alternate versions.

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS

Program	CENRAP Suggested		Westar Analyses		Reason for Difference
	Version	Level	Version	Level	
TERREL	3.311	030709	3.311	030709	
CTGCOMP	2.42	030709	2.22	030528	Version recommended is not available
CTGPROC	2.42	030709	2.42	030709	
MAKEGEO	2.22	030709	2.22	030709	
CALMM5	2.4	050413	2.4	050413	
CALMET	5.53a	040716	5.551	050310	CALMM5 v2.4 is not compatible with CALMET v5.53a
CALPUFF	5.711a	040716	5.727	050309	Use version compatible with CALMET v5.551
POSTUTIL	1.4	040818	1.4	040818	
CALPOST	5.51	030709	5.636	050218	Use version compatible with CALPUFF v5.636

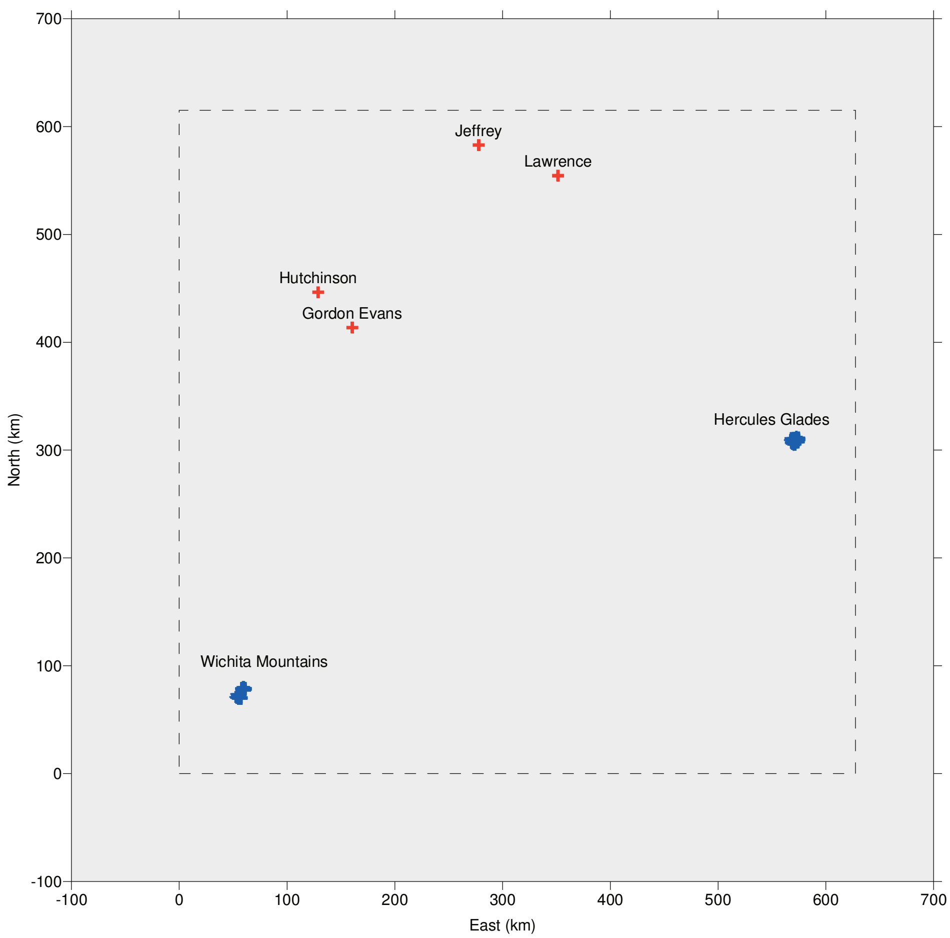
2.2 MODELING DOMAIN

The modeling domain will extend 50 km in all directions beyond Westar's BART-eligible sources and the two Class I areas of interest (HWG and WM). The map projection for the modeling domain will be Lambert Conformal Conic (LCC) and the coordinate system will be North American Datum 1927 (NAD27), which is an LCC projection. The meteorological grid spacing will be 2.5 km.

The southwest corner of the modeling domain is Latitude 34.08ºN, Longitude 99.35ºW which will be assigned as the 0, 0 reference point for the domain. The northeast corner of the modeling domain is approximately Latitude 39.78ºN, Longitude 92.05 ºW. At a grid spacing of 2.5 km, the number of X grid cells will be 251 and the number of Y grid cells will be 246.

Calculations showing the determination of these domain parameters are included in Appendix A. Further, Figure 2-1 provides a plot of the modeling domain with respect to the sources and Class I areas.

FIGURE 2-1. PROPOSED MODELING DOMAIN



3. CALMET

Westar will conduct a three-year CALMET analysis that incorporates both mesoscale model and observation meteorological data. The CALMET analysis will generate three years of data that will be input to CALPUFF. The CALMET model requires the input of geophysical data, meteorological data, and model parameter settings. The CALMET modeling procedures that will be used will generally follow the recommendations in CENRAP's protocol. However, some of CENRAP's recommendations only apply to CALMET analyses that incorporate mesoscale model meteorological data (and no observation data). Since the CALMET analysis for Westar's modeling will be a hybrid analysis (mesoscale model data plus observation data), it is expected that some parameters will be different.

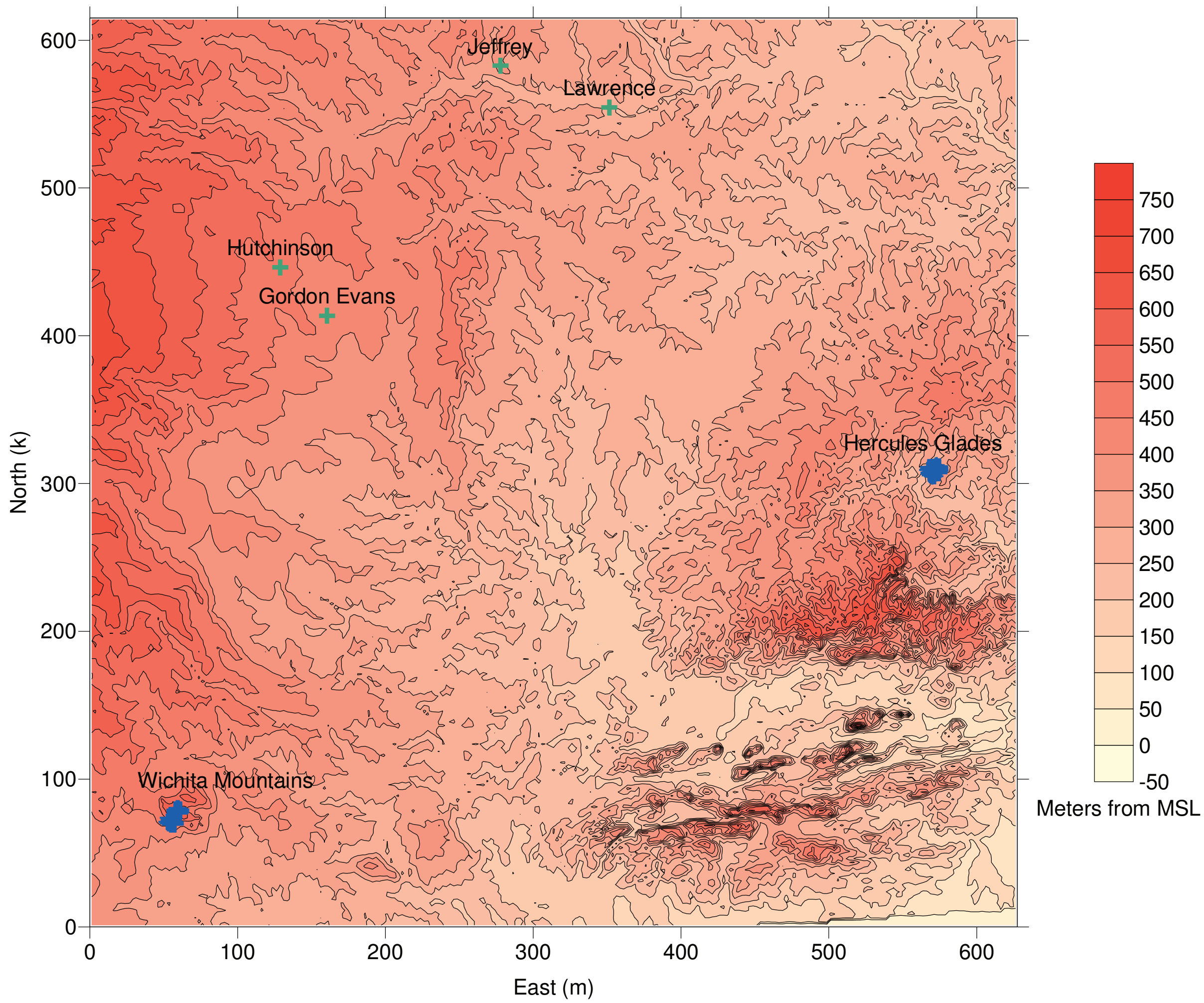
3.1 GEOPHYSICAL DATA

CALMET requires geophysical data to characterize the terrain and land use parameters that potentially affect dispersion. Terrain features affect flows and create turbulence in the atmosphere and are potentially subjected to higher concentrations of elevated puffs. Different land uses exhibit variable characteristics such as surface roughness, albedo, Bowen ratio, and leaf-area index that also effect turbulence and dispersion.

3.1.1 TERRAIN DATA

Terrain data from the United States Geological Survey (USGS) in 1-degree (1:250,000 scale or approximately 90 meter resolution) digital format will be used. A list of the USGS terrain files is provided in Appendix C. A plot of the land elevation for the modeling domain based on the referenced files is provided in Figure 3-1.

FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA

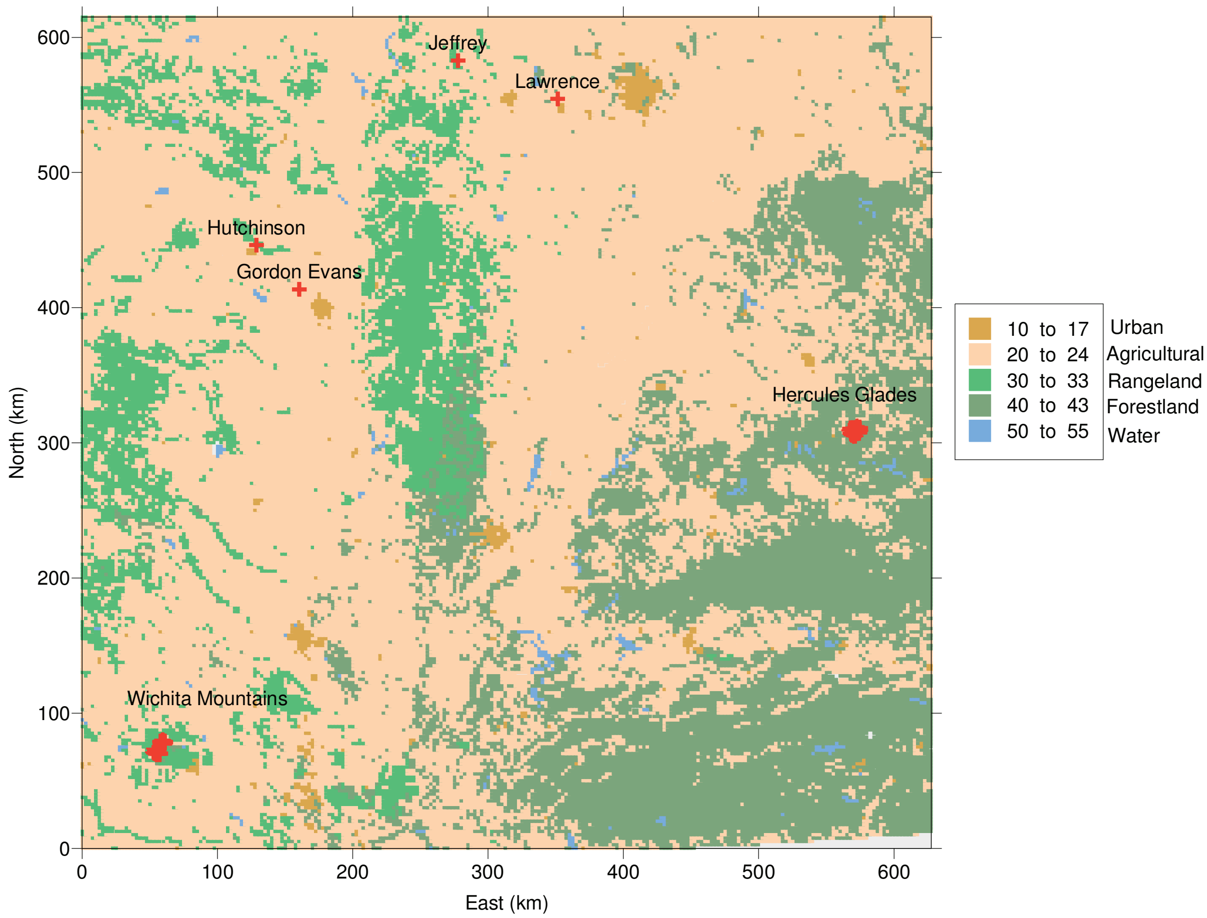


The USGS terrain data will be input into the TERREL program to generate grid-cell elevation averages across the modeling domain.

3.1.2 LAND USE DATA

USGS Composite Theme Grid (CTG) format Land Use and Land Cover (LULC) data files at 1:250,000 resolution will be used, where available. Where 1:250,000 land use data is not available, USGS data at 1:100,000 resolution will be used. A list of the USGS land use files is provided in Appendix C. A plot of the land use for the modeling domain based on the referenced files is provided in Figure 3-2.

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA



The LULC data will be input into the CTGPROC program to generate land use for each grid cell across the modeling domain. The USGS CTG format LULC data files must be compressed prior to use in the CTGPROC utility processor; therefore the files will be compressed using the program CTGCOMP.

3.1.3 COMPILING TERRAIN AND LAND USE DATA

The terrain data files output by the TERELL program and the LULC files output by CTGPROC program will be input to the program MAKEGEO to create a geophysical data file that will be input to CALMET.

3.2 METEOROLOGICAL DATA

CALMET will be used to assimilate data for 2001, 2002, and 2003 using mesoscale model output and National Weather Service (NWS) surface station observations, upper air station observations, and precipitation station observations to develop the meteorological field.

3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA

Hourly mesoscale data will be used to supplement the hourly surface, upper air, and precipitation observation data. The mesoscale data will be used to define the initial guess field for the CALMET simulations. The following 5th generation mesoscale model (MM5) meteorological data sets will be used:

- 2001 MM5 data at 36 km resolution processed for EPA by Alpine Geophysics
- 2002 MM5 data at 36 km resolution processed by Iowa DNR
- 2003 MM5 data set at 36 km resolution processed by the Midwest RPO

The MM5 data for the modeling domain will be extracted from the above MM5 data sets using the CALMM5 program. The MM5 data extraction will follow CENRAP's recommendations, meaning that all vertical layers will be extracted and vertical velocity, relative humidity, cloud/rain fields, and ice/snow fields will be included. An example CALMM5 input file is provided in Appendix B.

3.2.2 SURFACE METEOROLOGICAL DATA

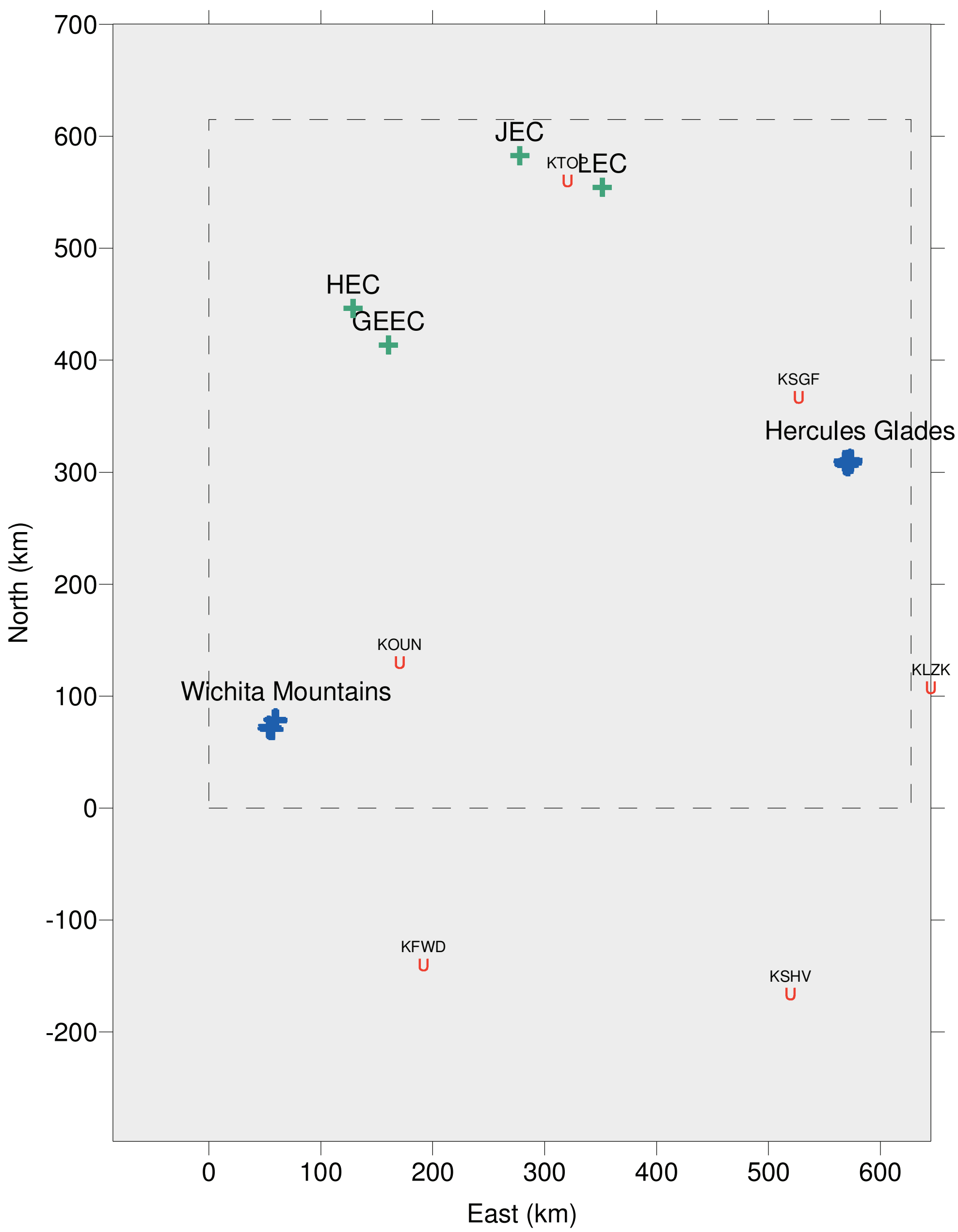
Parameters affecting turbulent dispersion that are observed hourly at surface stations include wind speed and direction, temperature, cloud cover and ceiling, relative humidity, and precipitation type. The surface stations from which data will be extracted are listed in Appendix D. The locations of the surface stations with respect to the modeling domain are shown in Figure 3-3. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using Version 5.55, Level: 050311 of EPA's SMERGE program.

FIGURE 3-3. PLOT OF SURFACE STATIONS

3.2.3 UPPER AIR METEOROLOGICAL DATA

Observations of meteorological conditions in the upper atmosphere provide a profile of turbulence from the surface through the depth of the boundary layer in which dispersion occurs. Upper air data are collected by balloons launched simultaneously across the observation network at 0000 Greenwich Mean Time (GMT) (6 o'clock PM in Kansas) and 1200 GMT (6 o'clock AM in Kansas). Sensors observe pressure, wind speed and direction, and temperature (among other parameters) as the balloon rises through the atmosphere. The upper air observation network is less dense than surface observation points since upper air conditions vary less and are generally not as affected by local effects (e.g., terrain or water bodies). The upper air stations from data will be extracted are listed in Appendix D. The locations of the upper air stations with respect to the modeling domain are shown in Figure 3-4. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using Version 5.52a, Level: 040716 of EPA's READ62 program.

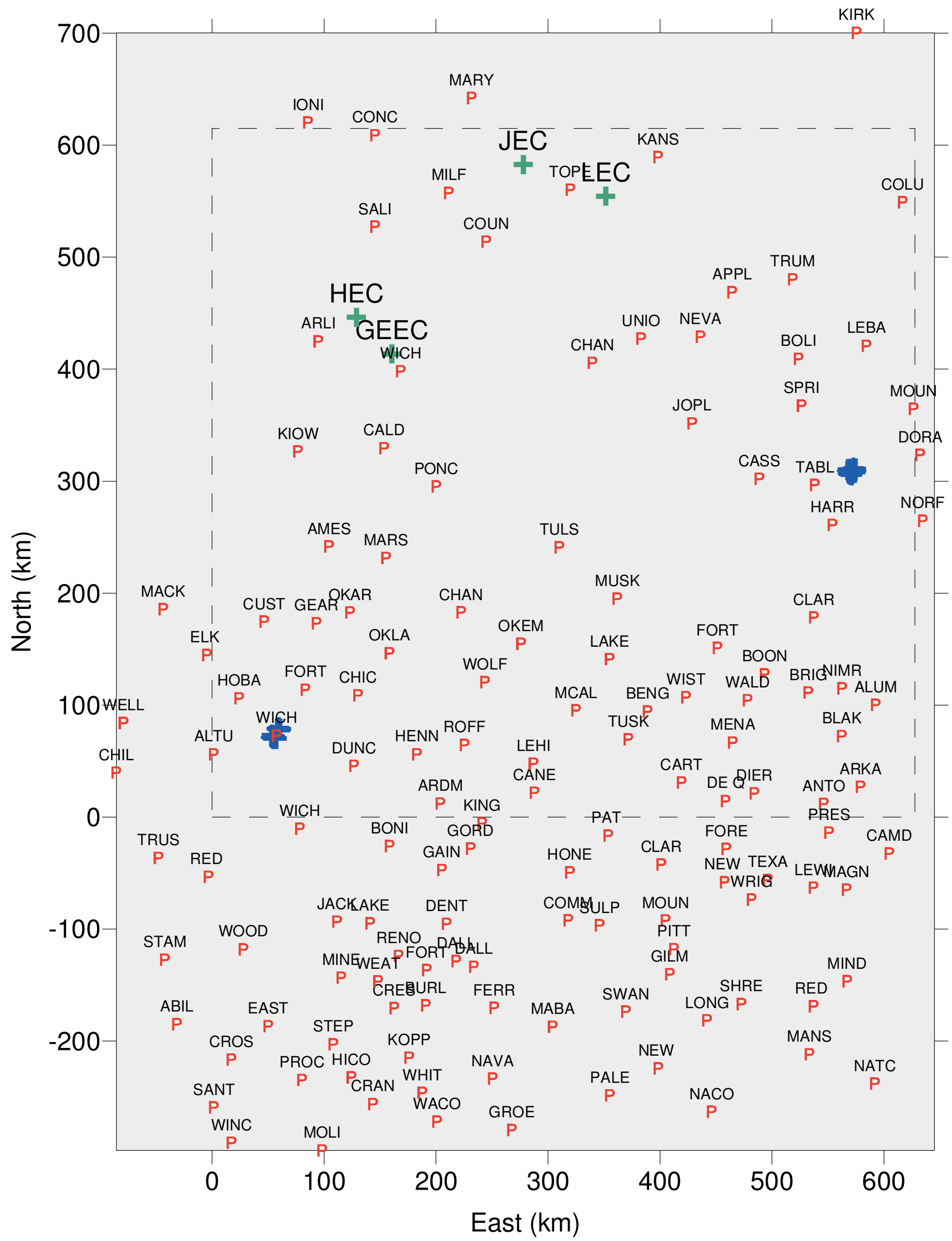
FIGURE 3-4. PLOT OF UPPER AIR STATIONS



3.2.4 PRECIPITATION METEOROLOGICAL DATA

The effects of chemical transformations and deposition processes on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of precipitation in the CALMET analysis. The precipitation stations from which data will be extracted are listed in Appendix D. The locations of the precipitation stations with respect to the modeling domain are shown in Figure 3-5. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using Version 5.31, Level: 030528 of EPA's PMERGE program.

FIGURE 3-5. PLOT OF PRECIPITATION METOROLOGICAL STATIONS



3.3 SUMMARY OF CALMET CONTROL PARAMETERS

Table 3-1 provides a listing of the CALMET parameters will be used in the modeling analysis. In addition to the parameters that will be used for the modeling, the table also lists CENRAP's recommended parameters for comparison. In cases where a parameter to be used is different than what CENRAP recommended, a short explanation as to the difference is proved. Note that most of the differences from CENRAP's recommended parameters are due to the inclusion of observation data into the modeling analysis, since CENRAP's parameters are based on a no-observation analysis.

TABLE 3-1. SUMMARY OF CALMET INPUTS

CALMET Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
NUSTA	Number of upper air data sites	0	6	Will use observations
NOWSTA	Number of overwater data sites	0	0	
IBYR	Starting year	2001	Appropriate met year	Years 2001, 2002, 2003
IBMO	Starting month	1	Appropriate month	Due to file size, analysis will be completed by month
IBHR	Starting hour	1	1	
IBTZ	Base time zone	6	6	
IRLG	Length of run	6	Varies with month	Due to file size, analysis will be completed by month
IRTYPE	Run type (1 for CALPUFF)	1	1	
LCALGRD	Compute CALFRID data fields (T = run CALGRID)	F	F	
ITEST	Stop run after SETUP to do input QA (2 = run)	2	2	
PMAP	Map projection	LCC	LCC	
RLAT0	Latitude (decimal degrees) of projection origin	40N	34.0825N	Appropriate for domain
RLON0	Longitude (decimal degrees) of projection origin	97W	99.3476W	Appropriate for domain
XLAT1	Latitude of 1st standard parallel	33N	34N	Appropriate for domain
XLAT2	Latitude of 2nd standard parallel	45N	40N	Appropriate for domain
DATUM	Datum region for output coordinates	WGS-G	NAS-C	Selected datum to match datum of land use data
NX	Number of X grid cells in meteorological grid	300	251	Appropriate for domain
NY	Number of Y grid cells in meteorological grid	192	246	Appropriate for domain
DGRIDKM	Grid spacing (km)	6.0	2.5	Refined grid spacing
XORIGKM	Ref. coordinate of SW corner of grid cell	-1008	0	Appropriate for domain
YORIGKM	Ref. coordinate of SW corner of grid cell	0.0	0	Appropriate for domain
NZ	Number of vertical layers	10	10	
ZFACE	Vertical cell face heights (NZ + 1 values)	0, 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000	0, 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000	

CALMET Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
LSAVE	Save met. data fields in an unformatted file?	T	T	
IFORMO	Type of unformatted output file (1 for CALPUFF)	1	1	
LPRINT	Print met. fields	F	F	
IPRINF	Print intervals	1	1	
IUVOUT(NZ)	Specify layers of u,v wind components to print	NZ*0	NZ*0	
IWOUT(NZ)	Specify layers of w wind component to print	NZ*0	NZ*0	
ITOUT(NZ)	Specify layers of 3D temperature field to print	NZ*0	NZ*0	
LDB	Print met data and variables	F	F	
NN1	First time step for debug data to be printed	1	1	
NN2	Last time step for debug data to be printed	1	2	Will generate debug data for a total of 2 time steps
IOUTD	Control variable for writing test/debug wind fields	0	0	
NZPRN2	Number of levels starting at surface to print	0	1	Default
IPRO	Print interpolated wind components	0	0	
IPR1	Print terrain adjusted surface wind components	0	0	
IPR2	Print initial divergence fields	0	0	
IPR3	Print final wind speed and direction	0	0	
IPR4	Print final divergence fields	0	0	
IPR5	Print winds after kinematic effects	0	0	
IPR6	Print winds after Froude number adjustment	0	0	
IPR7	Print winds after slope flows are added	0	0	
IPR8	Print final wind field components	0	0	
NOOBS	No observation mode (2 = No surface, overwater, or upper air observations; use MM5 for surface, overwater, and upper air data)	2	0	Will use observations
NSSTA	Number of meteorological stations in SURF.DAT file	0	32	Number of stations

CALMET Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
NPSTA	Number of precipitation stations in PRECIP.DAT file	0	138	Number of stations
ICLOUD	Gridded cloud fields (0 = no, 3 = Gridded cloud cover from prognostic relative humidity)	3	3	
IFORMS	Format of surface data (2 = formatted)	2	2	
IFORMP	Format of precipitation data (2 = formatted)	2	2	
IFORMC	Format of cloud data (2 = formatted)	2	1	N/A - No cloud data used in model
IWFCOD	Generate winds by diagnostic wind module? (1 = yes)	1	1	
IFRADJ	Adjust winds using Froude number effects? (1 = yes)	1	1	
IKINE	Adjust winds using kinematic effects? (0 = no)	0	1	Will compute kinematic effects in this analysis
IOBR	Use O'Brien procedure for vertical winds? (0 = no)	0	0	
ISLOPE	Compute slope flows? (1 = yes)	1	1	
IEXTRP	Extrapolate surface winds to upper layers (-1 = no extrapolation and ignore layer 1 of upper air station data)	-1	-4	-4 = Since observations are included in model, will use similarity theory and ignore layer 1 of upper air station data (FLAG default)
ICALM	Extrapolate surface winds even if calm? (0 = no)	0	0	
BIAS	Layer dependent biases weighting aloft measurements	0, 0, 0, 0, 0, 0, 0, 0, 0, 0	0, 0, 0, 0, 0, 0, 0, 0, 0, 0	
RMIN2	Minimum vertical extrapolation distance Distance (km) around an upper air site where vertical extrapolation is excluded (set to –1 if IEXTRP = ± 4)	-1	-1	
IPROG	Using prognostic or MM-FDDA data? (14 = Use winds from MM5.DAT as initial guess wind field)	14	14	
ISTEPPG	Timestep (hours) of the MM5 data	1	1	

CALMET Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
LVARY	Use varying radius of influence to develop surface winds?	T	F	Use FLAG default
RMAX1	Maximum radius of influence over land in surface layer (km)	30	36	Same as MM5 data spacing
RMAX2	Maximum radius of influence over land aloft (km)	30	36	Same as MM5 data spacing
RMAX3	Maximum radius of influence over water (km)	50	36	Same as MM5 data spacing
RMIN	Minimum radius of influence used anywhere (km)	0.1	0.1	
TERRAD	Radius of influence of terrain features (km)	12	12	
R1	Weighting of first guess surface field (km)	1	1	
R2	Weighting of first guess aloft field (km)	1	1	
RPROG	MM5 windfield weighting parameter (km)	0	0	
DIVLIM	Maximum acceptable divergence	5.E-6	5.E-6	
NITER	Max number of passes in divergence minimization	50	50	
NSMTH	Number of passes through smoothing filter in each layer of CALMET (NZ values)	2, 4, 4, 4, 4, 4, 4	2, 4, 4, 4, 4, 4, 4, 4, 4, 4	
NITR2	Max number of stations used in each layer for the interpolation of data to a grid point (NZ values)	5, 5, 5, 5, 5, 5, 5, 5, 5, 5	5, 5, 5, 5, 5, 5, 5, 5, 5, 5	
CRITFM	Critical Froude number	1.0	1.0	
ALPHA	Kinematic effects parameter	0.1	0.1	
FEXTR2	Scaling factor for extrapolating surface winds aloft	NZ*0.0	NZ*0.0	
NBAR	Number of terrain barriers	0	0	
IDIOTP1	Compute temperature from observations (0 = true)	0	0	
ISURFT	Surface station to use for surface temperature (between 1 and NSSTA)	4	4	
IDIOPT2	Domain-averaged wind component switch	0	0	

CALMET Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
IUPT	Station for lapse rates (between 1 and NUSTA)	2	2	
ZUPT	Depth through which lapse rate is calculated	200	200	
IDIOPT3	Domain averaged wind component switch	0	0	
IUPWND	Upper air station for domain winds	-1	-1	
ZUPWND	Bottom and top of layer through which the domain scale winds are computed	1., 1000.	1., 1000.	
IDIOPT4	Observed surface wind component switch	0	0	
IDIOPT5	Observed aloft wind component switch	0	0	
LLBREZE	Use lake breeze module?	F	F	
NBOX	Number of lake breeze regions	0	0	
NLB	Number of stations in the region	0	0	
METBXID(NLB)	Station IDs in the region	0	0	
CONSTB	Neutral stability mixing height coefficient	1.41	1.41	
CONSTE	Convective stability mixing height coefficient	0.15	0.15	
CONSTN	Stable stability mixing height coefficient	2400	2400	
CONSTW	Overwater mixing height coefficient	0.16	0.16	
FCORIOL	Absolute value of Coriolis parameter	1.E-4	1.E-4	
IAVEZI	Conduct spatial averaging? (1 = yes)	1	1	
MNMDAV	Max search radius in averaging process (number of grid cells)	10	10	
HAFANG	Half-angle of upwind looking cone for averaging (degrees)	30	30	
ILEVZI	Layers of wind use in upwind averaging (between 1 and NZ)	1	1	
DPTMIN	Minimum potential temperature lapse rate in the stable layer above the current convective mixing height	0.001	0.001	

CALMET Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
DZZI	Depth of layer above current convective mixing height through which lapse rate is computed (m)	200	200	
ZIMIN	Minimum overland mixing height (m)	50	50	
ZIMAX	Maximum overland mixing height (m)	3000	3000	
ZIMINW	Minimum overwater mixing height (m)	50	50	
ZIMAXW	Maximum overwater missing height (m)	3000	3000	
ITPROG	3D temperature from observations or from MM5?	2	0	Will use surface and upper air observations
IRAD	Type of interpolation (1 = 1/r)	1	1	
TRADKM	Temperature interpolation radius of influence (km)	36	36	
NUMTS	Max number of stations for temperature interpolations	5	5	
IAVET	Spatially average temperature? (1 = yes)	1	1	
TGDEFB	Temperature gradient below the mixing height over water (K/m)	-.0098	-0.0098	
TGDEFA	Temperature gradient above the mixing height over water (K/m)	-.0045	-0.0045	
JWAT1	Beginning land use categories over water	55	55	
JWAT2	Ending land use categories for water	55	55	
NFLAGP	Precipitation interpolation flag (2 = $1/r^2$)	2	2	
SIGMAP	Radius of influence for precipitation interpolation (km)	50	50	
CUTP	Minimum precipitation rate cut off (mm/hr)	0.01	0.01	

Westar will conduct a three-year CALPUFF analysis. The CALPUFF model requires the input of meteorological data output by CALMET, source emissions data, receptor data, ozone and ammonia data, and model parameter settings.

4.1 SOURCE EMISSIONS DATA

Westar will include emissions of SO_2, NO_x, and PM_{10} in the model.

4.1.1 SO_2 AND NO_X EMISSIONS

The SO_2 and NO_x emissions that will be included in the model are the 98th percentile of the 2002-2004 24-hour highest actual emissions rates, excluding periods of startup, shutdown, and malfunction. Table 4-1 provides a summary of these emission rates. Note that these are the same emission rates that Westar has previously provided to the KDHE as part of KDHE's request for information related to BART modeling.

TABLE 4-1. WESTAR BART-ELIGIBLE SOURCES NO_X AND SO_2 MAXIMUM ACTUAL 24-HOUR EMISSION RATES

	SO_2 (tons/24-hour)	NO_x (tons/24-hour)	SO_2 (lbs/hour)	NO_x (lbs/hour)
LEC Unit 5	22.9	13.2	1908.3	1100.0
JEC Unit 1	78.2	41.2	6516.7	3433.3
JEC Unit 2	81.5	41.3	6791.7	3441.7
HEC Unit 4 (North Stack)	14.7	2.35	1225.0	195.8
HEC Unit 4 (South Stack)	14.7	2.35	1225.0	195.8
GEEC Evans Unit 2 (A Stack)	25.5	12.1	2125.0	1004.2
GEEC Evans Unit 2 (B Stack)	25.5	12.1	2125.0	1004.2

4.1.2 TOTAL PM_{10} EMISSIONS

The PM_{10} emissions that will be included in the model are based on an estimate as to the 98th percentile of the 2002-2004 24-hour highest actual emissions rates. The method for estimating the 98th percentile of the 2002-2004 24-hour highest actual PM_{10} emissions rates is described below.

The 2002-2004 total annual calendar year PM_{10} emission rates were calculated by multiplying the annual fuel throughputs by the specific filterable and condensable AP-42 emission factors. Once the total annual PM_{10} emissions were determined based on AP-42, the annual emissions were divided by 365 days to determine the average actual 24-hour emission rate. Next, the average actual 24-hour

PM_{10} emission rates for each calendar year were averaged to determine the 2002-2004 actual average 24-hour emission rate. The maximum actual 24-hour emission rate was derived from the actual average 24-hour emission rate by multiplying the actual average 24-hour emission rate by a scaling factor. The scaling factor was derived as described below.

First, the 2002-2004 calendar year average actual 24-hour SO_2 emission rates (estimated as the actual annual emissions divided by 365 days per year) were determined. Next, the average 24-hour SO_2 emission rates for each calendar year were averaged to determine the 2002-2004 actual average 24-hour emission rate. Then, the 2002-2004 maximum actual 24-hour SO_2 emission rates that were listed in Table 4-1 were divided by the 2002-2004 actual average 24-hour emission rates. This value is the SO_2 scaling factor. The same procedure was followed to determine the NO_x scaling factor. The average of the SO_2 and NO_x scaling factors was selected as the multiplier to convert the maximum actual average 24-hour PM_{10} emission rates to the maximum actual 24-hour PM_{10} emission rates.

Table 4-2 provides a summary of the total PM_{10} emissions estimates using the methodology described above.

TABLE 4-2. ANNUAL TOTAL PM10 EMISSION ESTIMATES

4.1.3 SPECIATED PM_{10} EMISSIONS

The PM_{10} emissions will be speciated according to FLM guidance to include the following:

- Coarse particulate matter (PM_C)
- Fine particulate matter (PM_f)
- Sulfates (SO_4)
- Secondary organic aerosols (SOA)
- Elemental carbon (EC)

The PM_{10} emissions will be speciated according to the default speciation profiles prepared by the FLM's. Table 4-3 provides a summary of the proposed speciated emission rates that will be included in the model. Tables 4-4 through 4-8 provide the speciation methodology using the FLM speciation guidelines. Note that there currently is no guidance for speciation of PM from a coal boiler with a wet scrubber (LEC Unit 5). Thus, Westar will speciate PM from LEC Unit 5 using the speciation profile for PC boilers with ESPs.

TABLE 4-3. SUMMARY OF SPECIATED PM_{10} EMISSION ESTIMATES

	SO_4 (tons/ 24-hour)	PM_c (tons/ 24-hour)	PM_f (tons/ 24-hour)	SOA (tons/ 24-hour)	EC (tons/ 24-hour)	Total PM_{10} (tons/ 24-hour)
LEC Unit 5	1.152	0.551	0.425	0.288	0.016	2.43
JEC Unit 1	1.939	0.593	0.457	0.485	0.018	3.49
JEC Unit 2	1.849	0.565	0.436	0.462	0.017	3.33
HEC Unit 4 (North Stack)	0.070	0.206	0.513	0.012	0.041	0.84
HEC Unit 4 (South Stack)	0.070	0.206	0.513	0.012	0.041	0.84
GEEC Evans Unit 2 (A Stack)	0.125	0.338	0.842	0.022	0.067	1.39
GEEC Evans Unit 2 (B Stack)	0.125	0.338	0.842	0.022	0.067	1.39
	SO_4 (lbs/hr)	PM_c (lbs/hr)	PM_f (lbs/hr)	SOA (lbs/hr)	EC (lbs/hr)	Total PM_{10} (lbs/hr)
LEC Unit 5	96.0	45.9	35.4	24.0	1.4	202.6
JEC Unit 1	161.6	49.4	38.1	40.4	1.5	290.9
JEC Unit 2	154.1	47.1	36.3	38.5	1.4	277.4
HEC Unit 4 (North Stack)	5.8	17.2	42.7	1.0	3.4	70.2
HEC Unit 4 (South Stack)	5.8	17.2	42.7	1.0	3.4	70.2
GEEC Evans Unit 2 (A Stack)	10.4	28.2	70.1	1.8	5.6	116.2
GEEC Evans Unit 2 (B Stack)	10.4	28.2	70.1	1.8	5.6	116.2

TABLE 4-4. HEC UNIT 4 NORTH STACK PM SPECIATION ANALYSIS (SAME FOR SOUTH STACK)

Controlled PM10 Speciation from AP-42 Tables 1.3-2 & 1.3-4
Uncontrolled Utility Residual Oil Boiler

assumes firing of # **6** oil with a sulfur content of **1.77** %S; therefore, A = 2.356133333   Assume heating value of **156,270** Btu/Gal   f(RH) = **1**

Uncontrolled PM10 Emissions (**Bold** Values from Tables 1.3-2 and 1.3-4.)

Boiler Type	Total PM10 (lb/mGal)	Filterable (lb/mGal)	Coarse (lb/mGal)	Ext. Coef.	Fine (lb/mGal)	Fine Soil (lb/mGal)	Ext. Coef.	Fine EC (lb/mGal)	Ext. Coef.	Condensible (lb/mGal)	CPM IOR (lb/mGal)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mGal)
Utility	15.40	**13.90**	3.77	0.6	**10.13**	9.38	1	0.75	10	**1.5**	1.28	SO4	3*f(RH)	0.23

Uncontrolled PM10 Emissions

Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)
Utility	100%	90.3%	24.5%	0.6	65.8%	60.9%	1	4.9%	10	9.7%	8.3%	SO4	3*f(RH)	1.5%

Uncontrolled PM10 Emissions

Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)
Utility	0.10	0.09	0.02	0.6	0.06	0.06	1	0.005	10	0.01	0.01	SO4	3*f(RH)	0.001

If you are given Total PM10 emissions in lb/hr:

Uncontrolled PM10 Emissions (**Bold** Value is **Input** by user.)

Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)
Utility	**70.2**	63.3	17.2	0.6	46.2	42.7	1	3.4	10	6.8	5.8	SO4	3	1.0
		Weighted Extinction		10.3			42.7		34.2				17.4	

Coarse	24.5%
Fine Soil	60.9%
Fine EC	4.9%
CPM IOR	8.3%
CPM OR	1.5%
	100.0%

Coarse	17.2
Fine Soil	42.7
Fine EC	3.4
CPM IOR	5.8
CPM OR	1.0
	70.2

TABLE 4-5. GEEC UNIT 2 A STACK PM SPECIATION ANALYSIS (SAME FOR B STACK)

Controlled PM10 Speciation from AP-42 Tables 1.3-2 & 1.3-4
Uncontrolled Utility Residual Oil Boiler

assumes firing of # **6** oil with a sulfur content of **1.59** %S; therefore, A = 2.154533333 Assume heating value of **156,052** Btu/Gal f(RH) = **1**

	Uncontrolled PM10 Emissions (**Bold** Values from Tables 1.3-2 and 1.3-4.)												
Boiler Type	Total PM10 (lb/mGal)	Filterable (lb/mGal)	Coarse (lb/mGal)	Ext. Coef.	Fine (lb/mGal)	Fine Soil (lb/mGal)	Ext. Coef.	Fine EC (lb/mGal)	Ext. Coef.	Condensible (lb/mGal)	CPM IOR (lb/mGal)	Particle Type	Particle Ext.Coef.
Utility	14.21	**12.71**	3.45	0.6	**9.26**	8.58	1	0.69	10	**1.5**	1.28	SO4	3*f(RH)

	Uncontrolled PM10 Emissions												
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.
Utility	100%	89.4%	24.3%	0.6	65.2%	60.4%	1	4.8%	10	10.6%	9.0%	SO4	3*f(RH)

	Uncontrolled PM10 Emissions												
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
Utility	0.09	0.08	0.02	0.6	0.06	0.05	1	0.004	10	0.01	0.01	SO4	3*f(RH)

If you are given Total PM10 emissions in lb/hr:

	Uncontrolled PM10 Emissions (**Bold** Value is **Input** by user.)												
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.
Utility	**116.2**	103.9	28.2	0.6	75.7	70.1	1	5.6	10	12.3	10.4	SO4	3
		Weighted Extinction		16.9			70.1		56.0				31.3

Coarse	24.3%	Coarse	28.2
Fine Soil	60.4%	Fine Soil	70.1
Fine EC	4.8%	Fine EC	5.6
CPM IOR	9.0%	CPM IOR	10.4
CPM OR	1.6%	CPM OR	1.8
	100.0%		116.2

TABLE 4-6. JEC UNIT 1 PM SPECIATION ANALYSIS

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

assumes heating value of **12071.5** Btu/lb and a sulfur content of **0.55** % and an ash content of **4.82** % and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)												
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0353	0.0108	0.0060	0.6	0.0048	0.0046	1	0.00018	10	**0.025**	**0.020**	SO4	3*f(RH)

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)												
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.852	**0.260**	0.145	0.6	**0.116**	0.111	1	0.0043	10	0.592	0.473	SO4	3*f(RH)

	Controlled PM10 Emissions												
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	30.6%	17.0%	0.6	13.6%	13.1%	1	0.5%	10	69.4%	55.5%	SO4	3*f(RH)

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)												
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**290.9**	88.9	49.4	0.6	39.5	38.1	1	1.5	10	202.0	161.6	SO4	3
		Weighted Extinction		29.6			38.1		14.6				484.7

Coarse	17.0%	Coarse	49.4
Fine Soil	13.1%	Fine Soil	38.1
Fine EC	0.5%	Fine EC	1.5
CPM IOR	55.5%	CPM IOR	161.6
CPM OR	13.9%	CPM OR	40.4
	100.0%		290.9

TABLE 4-7. JEC UNIT 2 PM SPECIATION ANALYSIS

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

assumes heating value of **12071.5** Btu/lb and a sulfur content of **0.55** % and an ash content of **4.82** % and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)												
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0353	0.0108	0.0060	0.6	0.0048	0.0046	1	0.00018	10	**0.025**	**0.020**	SO4	3*f(RH)

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)												
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.852	**0.260**	0.145	0.6	**0.116**	0.111	1	0.0043	10	0.592	0.473	SO4	3*f(RH)

	Controlled PM10 Emissions												
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	30.6%	17.0%	0.6	13.6%	13.1%	1	0.5%	10	69.4%	55.5%	SO4	3*f(RH)

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)												
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**277.4**	84.8	47.1	0.6	37.7	36.3	1	1.4	10	192.6	154.1	SO4	3
		Weighted Extinction		28.3			36.3		13.9				462.2

Coarse	17.0%	Coarse	47.1
Fine Soil	13.1%	Fine Soil	36.3
Fine EC	0.5%	Fine EC	1.4
CPM IOR	55.5%	CPM IOR	154.1
CPM OR	13.9%	CPM OR	38.5
	100.0%		277.4

TABLE 4-8. LEC UNIT 5 PM SPECIATION ANALYSIS

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

assumes heating value of **12040** Btu/lb and a sulfur content of **0.49** % and an ash content of **5.84** % and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)													
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)
PC-DB	0.0321	0.0131	0.0073	0.6	0.0058	0.0056	1	0.00022	10	**0.019**	**0.015**	SO4	3*f(RH)	**0.004**

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)													
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)
PC-DB	0.773	**0.315**	0.175	0.6	**0.140**	0.135	1	0.0052	10	0.458	0.366	SO4	3*f(RH)	0.092

	Controlled PM10 Emissions													
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)
PC-DB	100%	40.8%	22.7%	0.6	18.1%	17.5%	1	0.7%	10	59.2%	47.4%	SO4	3*f(RH)	11.8%

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)													
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)
PC-DB	**202.6**	82.7	45.9	0.6	36.7	35.4	1	1.4	10	120.0	96.0	SO4	3	24.0
		Weighted Extinction		27.6			35.4		13.6				287.9	

Coarse	22.7%
Fine Soil	17.5%
Fine EC	0.7%
CPM IOR	47.4%
CPM OR	11.8%
	100.0%

Coarse	45.9
Fine Soil	35.4
Fine EC	1.4
CPM IOR	96.0
CPM OR	24.0
	202.6

4.1.4 STACK PARAMETERS

Table 4-9 provides a summary of the exhaust characteristics that will be modeled, including a summary of the emission rates presented elsewhere in this protocol for the BART-eligible sources.

TABLE 4-9. SUMMARY OF SPECIATED PM_{10} EMISSION ESTIMATES

	LEC Unit 5	JEC Unit 1	JEC Unit 2	HEC Unit 4 (South Stack)	HEC Unit 4 (North Stack)	GEEC Unit 2 (A Stack)	GEEC Unit 2 (B Stack)
Latitude (degrees)	39.007	39.287	39.287	38.092	38.092	37.793	37.793
Longitude (degrees)	95.275	96.116	96.116	97.873	97.873	97.518	97.518
Stack height (ft)	355	600	600	149	149	197	197
Stack Diameter (ft)	18.5	26.0	26.0	8.0	8.0	13.0	13.0
Exhaust Velocity (ft/s)	80.0	91.3	91.3	56.0	56.0	69.0	69.0
Exhaust Temperature (F)	166	300	300	313	313	290	290
NO_x (lb/hr)	1100.0	3433.3	3441.7	195.8	195.8	1004.2	1004.2
SO_2 (lb/hr)	1908.3	6516.7	6791.7	1225.0	1225.0	2125.0	2125.0
SO_4 (lb/hr)	96.0	161.6	154.1	5.8	5.8	10.4	10.4
PM_c (lb/hr)	45.9	49.4	47.1	17.2	17.2	28.2	28.2
PM_f (lb/hr)	35.4	38.1	36.3	42.7	42.7	70.1	70.1
SOA (lb/hr)	24.0	40.4	38.5	1.0	1.0	1.8	1.8
EC (lb/hr)	1.4	1.5	1.4	3.4	3.4	5.6	5.6

4.2 CLASS I AREA RECEPTORS

The National Park Service (NPS) has electronic files for each Class I area available on their website containing the locations and elevations of discrete Class I area receptors. The receptor files for Hercules-Glades Wilderness and the Wichita Mountains will be downloaded from the NPS website, converted into the LCC NAD27 projection, and incorporated into the CALPUFF model. The receptor locations for the Hercules-Glades Wilderness are show in Figure 4-1, and the locations for Wichita Mountains are shown in Figure 4-2.

FIGURE 4-1. HERCULES-GLADES WILDERNESS RECEPTOR LOCATIONS

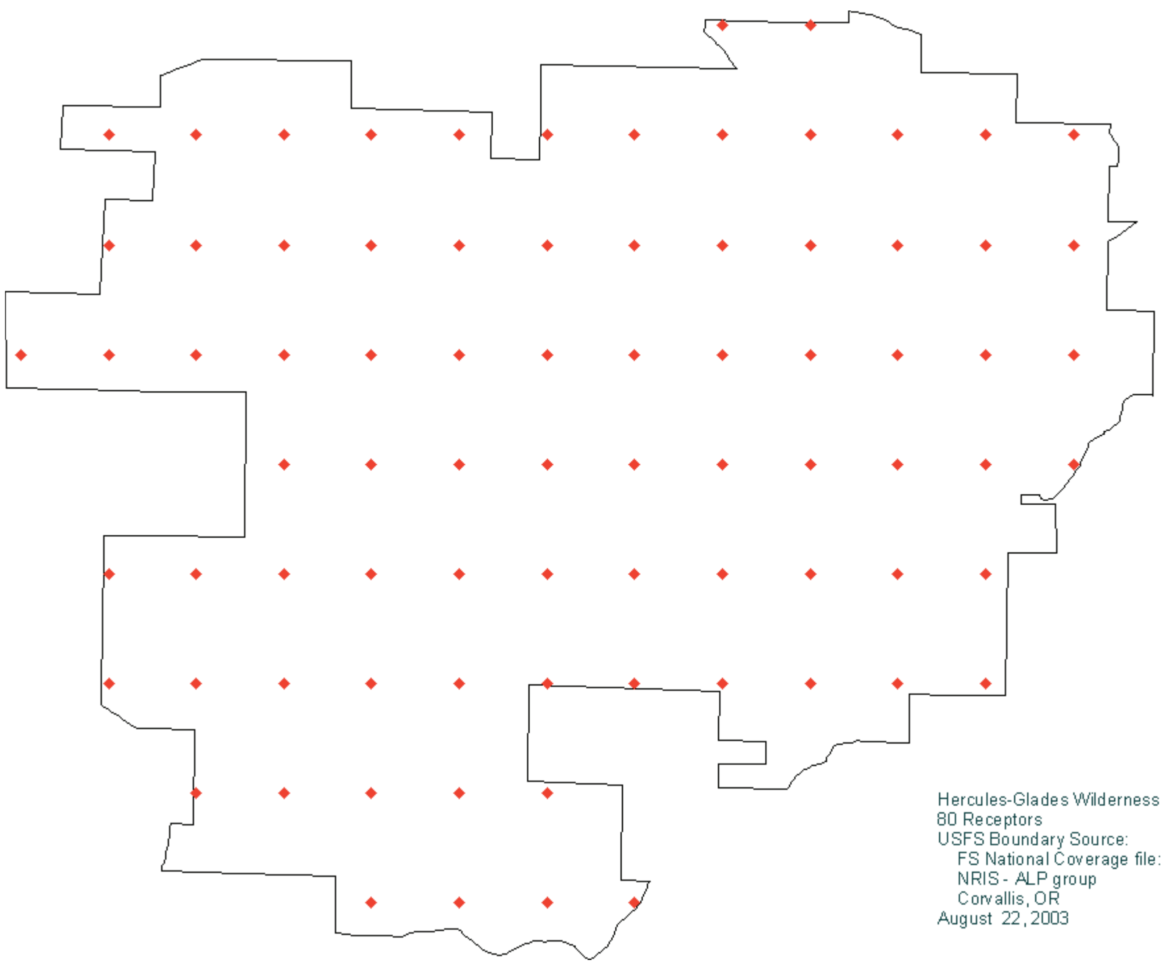
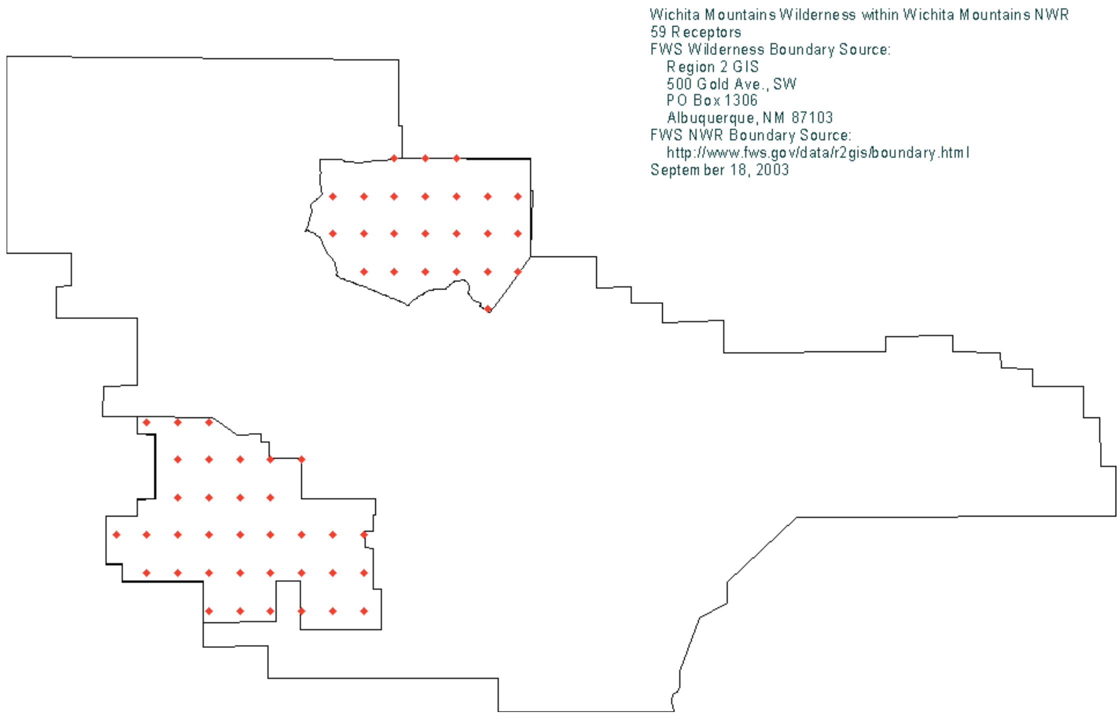


FIGURE 4-2. WICHITA MOUNTAINS RECEPTOR LOCATIONS



4.3 BACKGROUND OZONE

Background ozone concentrations are required in order to model the photochemical conversion of SO_2 and NO_x to sulfates (SO_4) and nitrates (NO_3). CALPUFF can use either a single background value representative of an area or hourly ozone data from one or more ozone monitoring stations. CENRAP recommends either developing background ozone estimates from ambient monitors located within the particular domain being modeled or developing background ammonia estimates from CENRAP's most recent CMAQ or CAMx simulation for the 2002 base year. Westar is proposing to incorporate hourly ozone data from three rural ozone monitors across the state of Kansas. The three monitors are listed in Table 4-10.

TABLE 4-10. SUMMARY OF OZONE MONITORS

Monitor ID	County	Latitude	Longitude
201910002 (Peck)	Sumner	37.477	97.366
201950001 (Cedar Bluff)	Trego	38.770	99.764
20107002 (Mine Creek)	Linn	38.135	94.732

Andy Hawkins of KDHE has made available processed ozone data files for 2001 through 2003 containing data from the above referenced stations. Westar is proposing to incorporate these files into the CALPUFF model.

4.4 BACKGROUND AMMONIA

Background ammonia concentrations are required to model the formation of ammonium sulfates and ammonium nitrates. CENRAP recommends developing background ammonia estimates from CENRAP's most recent CMAQ or CAMx simulation for the 2002 base year. Since CMAQ/CAMx modeled and observed monthly averaged ammonia concentrations exhibit wide spatial variability, CENRAP recommends obtaining separate monthly-averaged ammonia concentrations from CMAQ or CAMx for the CENRAP north, central and south modeling domains, respectively. These would then be used as input to CALPUFF. Since the data from CENRAP's CMAQ and CAMx simulations are not readily available, Westar is proposing to use a conservative monthly background concentration of 3 ppb. This background concentration is the value included in CENRAP's protocol as a default background value for the CENRAP region.

4.5 SUMMARY OF CALPUFF CONTROL PARAMETERS

Table 4-11 provides a listing of the CALPUFF parameters that Westar proposes to use in the modeling analysis. In addition to the parameters that will be used, the table also lists CENRAP's recommended parameters for comparison. In cases where a parameter to be used is different than what CENRAP recommended, a short explanation as to the difference is proved.

TABLE 4-11. SUMMARY OF CALPUFF INPUTS

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
METRUN	All model periods in met files will be run	0	0	
IBYR	Starting year	2001	Appropriate met year	Years 2001, 2002, 2003
IBMO	Starting month	1	1	
IBDY	Starting day	1	1	
IBHR	Starting hour	1	1	
XBTZ	Base time zone (6 = CST)	6	6	
IRLG	Length of run	8760	8760	
NSPEC	Number of MESOPUFF II chemical species	10	10	
NSE	Number of chemical species to be emitted	8	7	Appears to be an error in CENRAP's count of the emitted species (only 7 listed in Table B-4 of protocol)
ITEST	Program is executed after SETUP phase	2	2	

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
MRESTART	Do not read or write a restart file during run	0	0	
NRESPD	File written only at last period	0	0	
METFM	CALMET binary file (CALMET.MET)	1	1	
AVET	Averaging time in minutes	60	60	
PGTIME	PG Averaging time in minutes	60	60	
MGAUSS	Gaussian distribution used in near field	1	1	
MCTADJ	Partial plume path terrain adjustment	3	3	
MCTSG	Sub-grid-scale complex terrain not modeled	0	0	
MSLUG	Near-field puffs not modeled as elongated	0	0	
MTRANS	Transitional plume rise modeled	1	1	
MTIP	Stack tip downwash used	1	1	
MSHEAR	(0, 1) Vertical wind shear (not modeled, modeled)	0	0	
MSPLIT	Puffs are not split	0	1	Included puff splitting due to significant distance between sources and Class I areas
MCHEM	MESOPUFF II chemical parameterization scheme	1	1	
MAQCHEM	Aqueous phase transformation not modeled	0	0	
MWET	Wet removal modeled	1	1	
MDRY	Dry deposition modeled	1	1	
MDISP	PG dispersion coefficients	3	3	

<table>
<tr><th>CALPUFF Variable</th><th colspan="2">Description</th><th colspan="2">Value Included in CENRAP Protocol</th><th colspan="2">Value Westar Will Use</th><th colspan="2">Notes</th></tr>
<tr><td>MTURBVW</td><td colspan="2">Use both σ_v and σ_w from PROFILE.DAT to compute σ_y and σ_z (n/a)</td><td colspan="2">3</td><td colspan="2">3</td><td colspan="2"></td></tr>
<tr><td>MDISP2</td><td colspan="2">PG dispersion coefficients</td><td colspan="2">3</td><td colspan="2">3</td><td colspan="2"></td></tr>
<tr><td>MROUGH</td><td colspan="2">PG σ_y and σ_z not adjusted for roughness</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2"></td></tr>
<tr><td>MPARTL</td><td colspan="2">No partial plume penetration of elevated inversion</td><td colspan="2">1</td><td colspan="2">1</td><td colspan="2"></td></tr>
<tr><td>MTINV</td><td colspan="2">Strength of temperature inversion computed from default gradients</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2"></td></tr>
<tr><td>MPDF</td><td colspan="2">PDF not used for dispersion under convective conditions</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2"></td></tr>
<tr><td>MSGTIBL</td><td colspan="2">Sub-grid TIBL module not used for shoreline</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2"></td></tr>
<tr><td>MBCON</td><td colspan="2">Boundary concentration conditions not modeled</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2"></td></tr>
<tr><td>MFOG</td><td colspan="2">Do not configure for FOG model output</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2"></td></tr>
<tr><td>MREG</td><td colspan="2">Technical options must conform to USEPA Long Range Transport (LRT) guidance</td><td colspan="2">1</td><td colspan="2">1</td><td colspan="2"></td></tr>
<tr><td>CSPEC</td><td colspan="4">CENRAP</td><td colspan="4">Westar</td></tr>
<tr><td></td><td>Output Group Species</td><td>Modeled</td><td>Emitted</td><td>Dry Deposition</td><td>Output Group Species</td><td>Modeled</td><td>Emitted</td><td>Dry Deposition</td></tr>
<tr><td></td><td>SO_2</td><td>1</td><td>1</td><td>1</td><td>SO_2</td><td>1</td><td>1</td><td>1</td></tr>
<tr><td></td><td>SO4</td><td>1</td><td>0</td><td>2</td><td>SO4</td><td>1</td><td>1</td><td>2</td></tr>
<tr><td></td><td>NOX</td><td>1</td><td>1</td><td>1</td><td>NOX</td><td>1</td><td>1</td><td>1</td></tr>
<tr><td></td><td>HNO3</td><td>1</td><td>0</td><td>1</td><td>HNO3</td><td>1</td><td>0</td><td>1</td></tr>
<tr><td></td><td>NO3</td><td>1</td><td>0</td><td>2</td><td>NO3</td><td>1</td><td>0</td><td>2</td></tr>
<tr><td></td><td>NH3</td><td>1</td><td>1</td><td>1</td><td>NH3</td><td>1</td><td>0</td><td>1</td></tr>
<tr><td></td><td>PMC</td><td>1</td><td>1</td><td>2</td><td>PMC</td><td>1</td><td>1</td><td>2</td></tr>
<tr><td></td><td>PMF</td><td>1</td><td>1</td><td>2</td><td>PMF</td><td>1</td><td>1</td><td>2</td></tr>
<tr><td></td><td>EC</td><td>1</td><td>1</td><td>2</td><td>EC</td><td>1</td><td>1</td><td>2</td></tr>
<tr><td></td><td>SOA</td><td>1</td><td>1</td><td>2</td><td>SOA</td><td>1</td><td>1</td><td>2</td></tr>
<tr><td>PMAP</td><td colspan="2">Map projection</td><td colspan="2">UTM</td><td colspan="2">LCC</td><td colspan="2"></td></tr>
</table>

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
NX	Number of X grid cells in meteorological grid	66	251	Appropriate for domain and grid spacing
NY	Number of Y grid cells in meteorological grid	66	246	Appropriate for domain and grid spacing
NZ	Number of vertical layers in meteorological grid	10	10	
DGRIDKM	Grid spacing (km)	6	2.5	Refined grid size
ZFACE	Cell face heights in meteorological grid (m)	0, 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000	0, 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000	
XORIGKM	Reference X coordinate for SW corner of grid cell of meteorological grid (km)	5	0	Appropriate for domain
YORIGKM	Reference Y coordinate for SW corner of grid cell of meteorological grid (km)	3327	0	Appropriate for domain
IUTMZN	UTM zone of coordinates (NAD83)	12	14	Appropriate for domain
IBCOMP	X index of lower left corner of the computational grid	1	1	
JBCOMP	Y index of lower left corner of the computational grids	1	1	
IECOMP	X index of upper right corner of the computational grid	66	251	Appropriate for domain
JECOMP	Y index of upper right corner of the computational grid	66	246	Appropriate for domain
LSAMP	Sampling grid is not used	F	F	
IBSAMP	X index of lower left corner of sampling grid	1	1	
JBSAMP	Y index of lower left corner of sampling grid	1	1	
IESAMP	X index of upper right corner of sampling grid	66	251	Appropriate for domain

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
JESAMP	Y index of upper right corner of sampling grid	66	246	Appropriate for domain
MESHDN	Nesting factor of sampling grid	1	1	
ICON	Output file CONC.DAT containing concentrations is created	1	1	
IDRY	Output file DFLX.DAT containing dry fluxes is created	1	1	
IWET	Output file WFLX.DAT containing wet fluxes is created	1	1	
IVIS	Output file containing relative humidity data is created	1	1	
LCOMPRS	Perform data compression in output file	T	T	
IMFLX	Do not calculate mass fluzes across specific boundaries	0	0	
IMBAL	Mass balances for each species not reported hourly	0	0	
ICPRT	Print concentration fields to output list file	1	1	
IDPRT	Do not print dry flux fields to output list file	0	0	
IWPRT	Do not print wet flux fields to output list file	0	0	
ICFRQ	Concentration fields are printed to output list file every hour	1	1	
IDFRQ	Dry flux fields are printed to output list file every 1 hour	1	1	
IWFRQ	Wet flux fields are printed to output list file every 1 hour	1	1	

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
IPTRU	Units for line printer output are in g/m^3 for concentration and $g/m^2/s$ for deposition	3	3	
IMESG	Messages tracking the progress of run written to screen	2	2	
LDEBUG	Logical value for debug output	F	F	
IPFDEB	First puff to track	1	1	
NPFDEB	Number of puffs to track	1	1	
NN1	Meteorological period to start output	1	1	
NN2	Meteorological period to end output	10	10	
NHILL	Number of terrain features	0	0	
NCTREC	Number of special complex terrain receptors	0	0	
MHILL	Input terrain and receptor data for CTSG hills input in CTDM format	2	2	
XHILL2M	Conversion factor for changing horizontal dimensions to meters	1	1	
ZHILL2M	Conversion factor for changing vertical dimensions to meters	1	1	
XCTDMKM	X origin of CTDM system relative to CALPUFF coordinate system (km)	0	0	
YCTDMKM	Y origin of CTDM system relative to CALPUFF coordinate system (km)	0	0	
SO2	Diffusivity	0.1509	0.1509	
	Alpha star	1000	1000	
	Reactivity	8	8	

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
	Mesophyll resistance	0	0	
	Henry's Law coefficient	0.04	0.04	
NO_X	Diffusivity	0.1656	0.1656	
	Alpha star	1	1	
	Reactivity	8	8	
	Mesophyll resistance	5	5	
	Henry's Law coefficient	3.5	3.5	
HNO3	Diffusivity	0.1628	0.1628	
	Alpha star	1	1	
	Reactivity	18	18	
	Mesophyll resistance	0	0	
	Henry's Law coefficient	8.e-8	8.e-8	
SO4-2	Geomatric mass mean diameter of SO4-2 (µm)	0.48	0.48	
NO3-	Geometric mass mean diameter of NO3- (µm)	0.48	0.48	
PMC	Geometric mass mean diameter of PMC (µm)	6	6	
PMF	Geometric mass mean diameter of PMF (µm)	0.48	0.48	
EC	Geometric mass mean diameter of EC (µm)	0.48	0.48	
SOA	Geometric mass mean diameter of SOA (µm)	0.48	0.48	
RCUTR	Reference cuticle resistance (s/cm)	30	30	
RGR	Reference ground resistance (s/cm)	10	10	
REACTR	Reference pollutant reactivity	8	8	
NINT	Number of particle size intervals for effective particle deposition velocity	9	9	
IVEG	Vegetation in non-irrigated areas is active and unstressed	1	1	

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
SO_2	Scavenging coefficient for liquid precipitation (s^{-1})	3.21E-05	3.E-05	
	Scavenging coefficient for frozen precipitation (s^{-1})	0	0	
SO4-2	Scavenging coefficient for liquid precipitation (s^{-1})	1.0E-04	1.0E-04	
	Scavenging coefficient for frozen precipitation (s^{-1})	3.0E-05	3.0E-05	
HNO3	Scavenging coefficient for liquid precipitation (s^{-1})	6.0E-05	6.0E-05	
	Scavenging coefficient for frozen precipitation (s^{-1})	0	0	
NO3-	Scavenging coefficient for liquid precipitation (s^{-1})	1.0E-04	1.0E-04	
	Scavenging coefficient for frozen precipitation (s^{-1})	3.0E-05	3.0E-05	
NH3	Scavenging coefficient for liquid precipitation (s^{-1})	8.0E-05	NA	
	Scavenging coefficient for frozen precipitation (s^{-1})	0	NA	
PMC	Scavenging coefficient for liquid precipitation (s^{-1})	1.0E-4	1.0E-4	
	Scavenging coefficient for frozen precipitation (s^{-1})	3.0E-05	3.0E-05	
PMF	Scavenging coefficient for liquid precipitation (s^{-1})	1.0E-05	1.0E-05	

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
	Scavenging coefficient for frozen precipitation (s^{-1})	3.0E-05	3.0E-05	
EC	Scavenging coefficient for liquid precipitation (s^{-1})	1.0E-04	1.0E-04	
	Scavenging coefficient for frozen precipitation (s^{-1})	3.0E-05	3.0E-05	
OC	Scavenging coefficient for liquid precipitation (s^{-1})	1.0E-04	1.0E-04	
	Scavenging coefficient for frozen precipitation (s^{-1})	3.0E-05	3.0E-05	
MOZ	Read ozone background concentrations from ozone.dat file (measured values)	1	1	
BCKO3	Background ozone concentration (ppb)	12*40	NA	Used ozone data file
BCKNH3	Background ammonia concentration (ppb)	12*3	12*3	
RNITE1	Nighttime NO2 loss rate is %/hour	0.2	0.2	
RNITE2	Nighttime NO_X loss rate is %/hour	2	2	
RNITE3	Nighttime HNO3 loss rate is %/hour	2	2	
MH2O2	Background H2O2 concentrations	1	0	Need to choose 0 in order to use monthly background value
BCKH2O2	Background monthly H2O2 concentrations	1	12*1	
BCKPMF	Fine particulate concentration for SOA option ($\mu g/m^3$)	1	1	
OFRAC	Organic fraction of fine particulate for SOA option	.2	0.15,0.15,0.2,0.2,0.2, 0.2,0.2,0.2,0.2,0.2, 0.2,0.15	Irrelevant, since MCHEM not equal to 4

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
VCNX	VOC/NO_X ratio for SOA option	50	50	
SYDEP	Horizontal size of a puff in meters beyond which the time dependant dispersion equation of Heffter is used	550	550	
MHFTSZ	Do not use Heffter formulas for sigma z	0	0	
JSUP	Stability class used to determine dispersion rates for puffs above boundary layer	5	5	
CONK1	Vertical dispersion constant for stable conditions	0.01	0.01	
CONK2	Vertical dispersion constant for neutral/stable conditions	0.1	0.1	
TBD	Use ISC transition point for determining the transition point between the Schulman-Scire to Huber-Snyder Building Downwash scheme	0.5	0.5	
IURB1	Lower range of land use categories for which urban dispersion is assumed	10	10	
IURB2	Upper range of land use categories for which urban dispersion is assumed	19	19	
ILANDUIN	Land use category for modeling domain	*	*	
XLAIIN	Leaf area index for modeling domain	*	*	
ZOIN	Roughness length in meters for modeling domain	*	*	

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
ELEVIN	Elevation above sea level	*	*	
XLATIN	North latitude of station in degrees	-	-	
XLONIN	South latitude of station in degrees	-	-	
ANEMHT	Anemometer height in meters	10	10	
ISIGMAV	Sigma-v is read for lateral turbulence data	1	1	
IMIXCTDM	Predicted mixing heights are used	0	0	
XMXLEN	Maximum length of emitted slug in meteorological grid units	1	1	
XSAMLEN	Maximum travel distance of slug or puff in meteorological grid units during one sampling unit	10	10	
MXNEW	Maximum number of puffs or slugs released from one source during one time step	60	60	
MXSAM	Maximum number of sampling steps during one time step for a puff or slug	60	60	
NCOUNT	Number of iterations used when computing the transport wind for a sampling step that includes transitional plume rise	2	2	
SYMIN	Minimum sigma y in meters for a new puff or slug	1	1	
SZMIN	Minimum sigma z in meters for a new puff or slug	1	1	
SVMIN	Minimum lateral turbulence velocities (m/s)	0.5	0.5	
SWMIN	Minimum vertical turbulence velocities (m/s)	0.20, 0.12, 0.08, 0.06, 0.03, 0.016	0.20, 0.12, 0.08, 0.06, 0.03, 0.016	

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
WSCALM	Minimum non-calm wind speeds (m/s)	0.5	0.5	
XMAXZI	Maximum mixing height (m)	3000	3000	
XMINZI	Minimum mixing height (m)	20	20	
SL2PF	Maximum σy/puff length	10	10	
PLXO	Wind speed power-law exponents	0.07, 0.07, 0.10, 0.15, 0.35, 0.55	0.07, 0.07, 0.10, 0.15, 0.35, 0.55	
WSCAT	Upper bounds of 1st 5 wind speed classes	1.54, 3.09, 5.14, 8.23, 10.80	1.54, 3.09, 5.14, 8.23, 10.80	
PGGO	Potential temp gradients PG E & F (deg/km)	0.020, 0.035	0.020, 0.035	
CDIV	Divergence criterion for dw/dz (1/s)	0.01	0.01	
PPC	Plume path coefficients (only if MCTADJ = 3)	0.5, 0.5, 0.5, 0.5, 0.35, 0.35	0.5, 0.5, 0.5, 0.5, 0.35, 0.35	
NSPLIT	Number of puffs when split	3	3	
IRESPLIT	Hours when puff is eligible to split	1900	Hour 17	Should be by hour of day – 1900 is hour 17
ZISPLIT	Previous hours minimum mixing height, m	100	100	
ROLDMAX	Previous max mixing height/current height ratio, must be less than this value to allow puff to split	0.25	0.25	
NSPLITH	Number of puffs resulting from a split	5	5	
SYSPLITH	Minimum sigma-y of puff before it may split	1.0	1.0	
SHSPLITH	Minimum puff elongation rate from wind shear before puff may split	2.0	2.0	

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
CNSPLITH	Minimum species concentration before a puff may split	1.0E-07	1.0E-07	
EPSSLUG	Criterion for SLUG sampling	1.0E-04	1.0E-04	
EPSAREA	Criterion for area source integration	1.0E-06	1.0E-06	
DSRISE	Trajectory step length for numerical site algorithm	1.0	1.0	
NPT1	Number of point sources with constant stack parameters or variable emission rate scale factors	Varies by scenario	Varies by scenario	
IPTU	Units for point source emission rates are g/s	1	3	Used different units (3 = lb/hr)
NSPT1	Number of source-species combinations with variable emissions scaling factors	-	-	
NPT2	Number of point sources with variable emission parameters provided in external file	-	-	
MISC	Other point source inputs include stack height, stack diameter, exit temperature, exit velocity, downwash flag and emissions by species	-	-	
NAR1	Number of polygon area sources	Varies by scenario	0	None modeled
IARU	Units for area source emission rates are $g/m^2/s$	1	1	
NSAR1	Number of source species combinations with variable emissions scaling factors	-	-	

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
NAR2	Number of buoyant polygon area sources with variable location and emission parameters	-	-	
NLN2	Number of buoyant line sources with variable location and emission parameters	-	0	None modeled
NLINES	Number of buoyant line sources	-	-	
ILNU	Units for line source emission rates in g/s	-	-	
NSLN1	Number of source-species combinations with variable emissions scaling factors	-	-	
MXNSEG	Maximum number of segments used to model each line	-	-	
NLRISE	Number of distance at which transitional rise is computed	-	-	
XL	Average line source length (m)	-	-	
HBL	Average height of line source height (m)	-	-	
WBL	Average building width (m)	-	-	
WML	Average line source width (m)	-	-	
DXL	Average separation between buildings (m)	-	-	
FPRIMEL	Average buoyancy parameter (m4/s3)	-	-	
NVL1	Number of volume sources	-	0	None modeled
IVLU	Units for volume source emission rates in grams/second	-	-	

CALPUFF Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
NSVL1	Number of source-species combinations with variable emissions scaling factors	-	-	
IGRDVL	Gridded volume source data is not used	-	-	
VEFFHT	Effective height of emissions (m)	-	-	
VSIGYI	Initial sigma-y value	-	-	
VSIGZI	Initial sigma-z value	-	-	
NREC	Number of non-gridded receptors	5630	139	Receptor data provided in Appendix

Westar will conduct a three-year CALPOST analysis to determine the change in light extinction caused by our BART-eligible sources when compared to a natural background. The CALPOST model requires the input of concentration data output by CALPUFF.

5.1 Light Extinction Algorithm

Westar will utilize EPA's currently approved algorithm for reconstructing light extinction (as opposed to the new equation for reconstructing light extinction recommended by the IMPROVE Steering Committee). The light extinction equation is provided below.

$$b_{ext} = 3*f(RH)*[(NH_4)_2SO_4] + 3*f(RH)*[NH_4NO3] + 4*[OC] + 1*[PM_f] + 0.6*[PM_c] + 10*[EC] + b_{Ray}$$

The algorithm will be used to calculate the daily light extinction attributable to Westar's BART-eligible sources and light extinction attributable to a natural background. The change in deciviews based on the source and background light extinctions will be evaluated using the equation below.

$$\Delta dv = 10*\ln\left[\frac{b_{ext,\ background} + b_{ext,\ source}}{b_{ext,\ background}}\right]$$

5.2 CALPOST Processing Method

Westar will use CALPOST Method 6, which calculates hourly light extinction impacts for the source and background using monthly average relative humidity adjustment factors. Westar will use monthly Class I area-specific relative humidity adjustment factors based on the centroid of the Class I areas as included in Table A-3 of EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program.* The factors for Hercules Glades Wilderness and Wichita Mountains are provided in Table 5-1.

Table 5-1. Monthly Humidity Factors

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hercules-Glades	3.2	2.9	2.7	2.7	3.3	3.3	3.3	3.3	3.4	3.1	3.1	3.3
Wichita Mountains	2.7	2.6	2.4	2.4	3.0	2.7	2.3	2.5	2.9	2.6	2.7	2.8

5.3 NATURAL BACKGROUND

Westar will use EPA's default average annual aerosol concentrations for the western half of the U.S. that are included in Table 2-1 of EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program.* The annual average concentrations are provided in Table 5-2.

TABLE 5-2. DEFAULT WEST AVERAGE ANNUAL NATURAL BACKGROUND LEVELS

Component	Average Annual Natural Background ($\mu g/m^3$)
Ammonium Sulfate	0.12
Ammonium Nitrate	0.1
Organic Carbon Mass	0.47
Elemental Carbon	0.02
Soil	0.5
Coarse Mass	3

5.4 EVALUATING BART-EXEMPTION

Westar will compare the 98th percentile of the 2001 through 2003 daily Δdv values output by CALPOST (22nd highest daily value) to a contribution threshold of 0.5 Δdv. If the 98th percentile daily Δdv values output by CALPOST is less 0.5 Δdv, then it will be concluded that the source is exempt from BART and that no further analysis is necessary. If the 98th percentile of the daily Δdv values output by CALPOST is greater than 0.5 Δdv, then it will be concluded that further analysis is necessary.

5.5 SUMMARY OF CALPOST CONTROL PARAMETERS

Table 5-3 provides a listing of the CALPOST parameters that Westar proposes to use in the modeling analysis. In addition to the parameters that will be used for the modeling, the table also lists CENRAP's recommended parameters for comparison. In cases where a parameter to be used is different than what CENRAP recommended, a short explanation as to the difference is proved.

TABLE 5-3. SUMMARY OF CALPOST INPUTS

CALPOST Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
ISYR	Starting year	2001	Appropriate met year	Years 2001, 2002, 2003
ISMO	Starting month	1	1	
ISDY	Starting day	1	1	
ISHR	Starting hour	0	1	All CALPUFF periods will be included
NPER	Number of periods to process	8760	8760	

CALPOST Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
NREP	Process every hour of data? 1 = yes	1	1	
ASPEC	Process species for visibility	VISIB	VISIB	
ILAYER	Layer/deposition code; 1 for CALPUFF concentrations	1	1	
A	Scaling factor, slope	0	0	
B	Scaling factor, intercept	0	0	
LBACK	Add hourly background concentrations of fluxes?	F	F	
LG	Process gridded receptors?	F	F	
LD	Process discrete receptors?	T	T	
LCT	Process complex terrain receptors?	F	F	
LDRING	Report receptor ring results?	F	F	
NDRECP	Select all discrete receptors	-1	Varies	As appropriate for Class I area being analyzed
IBGRID	X index of LL corner of receptor grid	-1	-1	
JBGRID	Y index of LL corner of receptor grid	-1	-1	
IEGRID	X index of UR corner of receptor grid	-1	-1	
JEGRID	Y index of UR corner of receptor grid	-1	-1	
NGONOFF	Number of gridded receptor rows	0	0	
NGXRECP	Exclude specific gridded receptors, Yes = 0	0	0	
RHMAX	Maximum RH% used in particle growth curve	95	95	
LVSO4	Compute light extinction for sulfate?	T	T	

CALPOST Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
LVNO3	Compute light extinction for nitrate?	T	T	
LVOC	Compute light extinction for organic carbon?	T	T	
LVMPC	Compute light extinction for coarse particles?	T	T	
LVMPF	Compute light extinction for fine particles?	T	T	
LVEC	Compute light extinction for elemental carbon?	T	T	
LVBK	Include background in extinction calculation?	T	T	
SPECPMC	Coarse particulate species	PMC	PMC	
SPECPMF	Fine particulate species	PM_{10}	PMF	Notation difference
EEPMC	Extinction efficiency for coarse particulates	0.6	0.6	
EEPMF	Extinction efficiency for fine particles?	1.0	1.0	
EEPMCBCK	Extinction efficiency for coarse part. Background	0.6	0.6	
EESO4	Extinction efficiency for ammonium sulfate	3.0	3.0	
EENO3	Extinction efficiency for ammonium nitrate	3.0	3.0	
EEOC	Extinction efficiency for organic carbon	4.0	4.0	
EESOIL	Extinction efficiency for soil	1.0	1.0	
EEEC	Extinction efficiency for elemental carbon	10.0	10.0	
MVISBK	Method 6 for background light extinction	6	6	
BEXTBTBK	Background extinction for MVISBK=1	12	Not Used	Not necessary since MVISBK=6

CALPOST Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
RHFRAC	% of particles affected by RH	10	Not Used	Not necessary since MVISBK=6
RHFAC	Extinction coefficients for modeled and background hygroscopic species computed using EPA (2003) monthly RH adjustment factors	Depends on Class I Area	For Hercules-Glades: 3.2, 2.9, 2.7, 2.7, 3.3, 3.3, 3.3, 3.3, 3.4, 3.1, 3.1, 3.3 For Wichita Mtns: 2.7, 2.6, 2.4, 2.4, 3.0, 2.7, 2.3, 2.5, 2.9, 2.6, 2.7, 2.8	As appropriate for Class I area
BKSO4	Background sulfate extinction coeff - west	0.12	0.12	
BKNO3	Background nitrate extinction coeff – west	0.10	0.10	
BKPMC	Background coarse part. extinction coeff – west	3.00	3.00	
BKSOC	Background organic carbon extinction coeff – west	0.47	0.47	
BKSOIL	Background soil extinction coeff – west	0.50	0.50	
BKSEC	Background elemental carbon extinction coeff – west	0.02	0.02	
BKSO4	Background sulfate extinction coeff – east	0.23	Not Used	West analysis only
BKNO3	Background nitrate extinction coeff – east	0.10	Not Used	West analysis only
BKPMC	Background sulfate extinction coeff – west	3.00	Not Used	West analysis only
BKSOC	Background organic carbon extinction coeff – east	1.40	Not Used	West analysis only
BKSSOIL	Background soil extinction coeff – east	0.50	Not Used	West analysis only
BKSEC	Background elemental carbon extinction coeff – east	0.02	Not Used	West analysis only

CALPOST Variable	Description	Value Included in CENRAP Protocol	Value Westar Will Use	Notes
BEXTRAY	Extinction due to Rayleigh scattering (1/Mm)	10.0	10.0	
LDOC	Print documentation image?	F	F	
IPTRU	Print output units for concentrations and for deposition	3	1	Units preference
L1HR	Report 1 hr averaging times	F	F	
L3HR	Report 3 hr averaging times	F	F	
L24HR	Report 24 hr averaging times	T	T	
LRUNL	Report run-length averaging times	F	F	
LT50	Top 50 table	F	F	
LTOPN	Top N table	F	F	
NTOP	Number of Top-N values at each receptor	4	4	
ITOP	Ranks of Top-N values at each receptor	1,2,3,4	1,2,3,4	
LEXCD	Threshold exceedances counts	F	F	
THRESH1	Averaging time threshold for 1 hr averages	-1	-1	
THRESH3	Averaging time threshold for 3 hr averages	-1	-1	
THRESH24	Averaging time threshold for 24 hr averages	-1	-0.2	Lower threshold – no effect on results
THRESHN	Averaging time threshold for NAVG-hr averages	-1	-1	
NDAY	Accumulation period, days	0	0	
NCOUNT	Number of exceedances allowed	1	1	
LECHO	Echo option	F	F	
LTIME	Time series option	F	F	
LPLT	Plot file option	F	F	
LGRD	Use grid format instead of DATA format	F	F	
LDEBUG	Output information for debugging?	F	F	

APPENDIX A

MODELING DOMAIN

TABLE A-1. DETERMINATION OF MODELING DOMAIN

		X	Y	Lat NAD27	Lon NAD27
Gordon Evans	**NAD 27, Zone 14**	630.457	4183.633	37.793	97.518
Hutchinson	**NAD 27, Zone 14**	598.828	4216.416	38.092	97.873
Jeffrey	**NAD 27, Zone 14**	748.746	4352.838	39.287	96.116
Lawrence	**NAD 27, Zone 14**	822.578	4323.950	39.007	95.275

Hercules-Glades Wilderness Area

	UTM = NAD 27, Zone 14		Lat NAD27	Lon NAD27
SouthWest	1038.441	4073.213	36.654	92.979
NorthEast	1046.917	4081.226	36.721	92.879
SouthEast	1047.394	4073.782	36.654	92.879
NorthWest	1037.973	4080.657	36.721	92.979

Wichita Mountains Area

	UTM = NAD 27, Zone 14		Lat NAD27	Lon NAD27
SouthWest	530.176	3840.082	34.7041	98.6705
NorthEast	520.233	3851.144	34.8041	98.7788
SouthEast	520.258	3840.055	34.7041	98.7788
NorthWest	530.140	3851.171	34.8041	98.6705

50 distance from facility
50 distance from Hercules-Glades WA

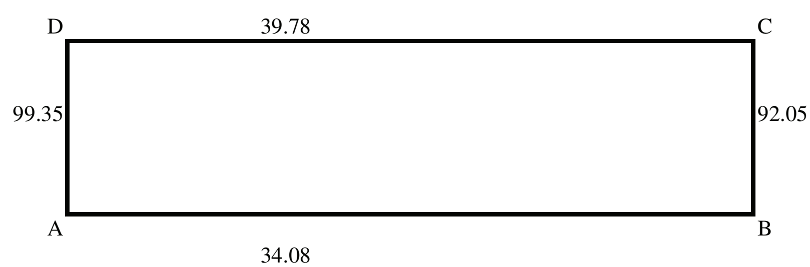
	UTM = NAD 27, Zone 14		Lat NAD27	Lon NAD27
POINT	**UTM (KM) E**	**UTM(KM) N**	**Latitude (Decimal)**	**Longitude (Decimal)**
A	470.233	3790.055	34.25	99.32
B	1097.394	3790.055	34.08	92.53
C	1097.394	4402.838	39.57	92.05
D	470.233	4402.838	39.78	99.35

2.5 km grid spacing

MAX HORIZONTAL DIST (KM)
627.16 251 NX

MAX VERTICAL DIST (KM)
612.78 246 NY

Modeling Domain



APPENDIX B

EXAMPLE OF CALMM5 INPUT FILE

FIGURE B-1. EXAMPLE CALMM5 INPUT FILE

```
CALMM5 VER3 Output Sample Input File
33            ! Number of MM5 Output files (0 for auto)
i:\mm5\MMOUT_DOMAIN1_01_2000123112-2001010600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_02_2000123112-2001010600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_03_2000123112-2001010600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_04_2000123112-2001010600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_05_2000123112-2001010600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_01_2001010512-2001011100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_02_2001010512-2001011100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_03_2001010512-2001011100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_04_2001010512-2001011100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_05_2001010512-2001011100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_01_2001011012-2001011600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_02_2001011012-2001011600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_03_2001011012-2001011600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_04_2001011012-2001011600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_05_2001011012-2001011600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_01_2001011512-2001012100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_02_2001011512-2001012100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_03_2001011512-2001012100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_04_2001011512-2001012100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_05_2001011512-2001012100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_01_2001012012-2001012600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_02_2001012012-2001012600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_03_2001012012-2001012600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_04_2001012012-2001012600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_05_2001012012-2001012600 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_01_2001012512-2001013100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_02_2001012512-2001013100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_03_2001012512-2001013100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_04_2001012512-2001013100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_05_2001012512-2001013100 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_01_2001013012-2001020500 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_02_2001013012-2001020500 ! MM5 input file name (no space before or within filename)
i:\mm5\MMOUT_DOMAIN1_03_2001013012-2001020500 ! MM5 input file name (no space before or within filename)
R:\WestarBART\CALMM5\2001Outputs\Jan.m3d ! CALMM5 output file name  (no space before or within filename)
R:\WestarBART\CALMM5\2001Outputs\Jan.lst ! CALMM5 list file name (no space before or within filename)
1             ! Options for selecting a region (1: use lat/long; 2: use J/I)
34.08         ! Southernmost latitude (in decimal, positive for NH), or J1/Y1
39.78         ! Northermost  latitude (in decimal, positive for NH), or J2/Y2
-99.35        ! Westernmost  longitude (in decimal, negative for WH), or I1/X1
-92.05        ! Easternmost  longitude (in decimal, negative for WH), or I2/X2
2001010107    ! Starting date (year-month-day-UTC hour)(yymmddhh)
2001020106    ! Ending date
1             ! Output format (1,2,3,4,5, 6 - see readme.cm5 for details)
Keep this line - The following lines vary depending on the output format selected
1 1 1 1 0     ! Output W, RH, cloud and rain, ice and snow, graupel
0             ! Flag for 2-D variables output (1/0: output/not)
1             ! Lowest extraction level in MM5
34            ! Highest extraction level in MM5
```

APPENDIX C

GEOPHYSICAL DATA

TABLE C-1. LAND USE DATA USED IN ANALYSIS

1:250,000 scale data	1:100,000 scale data
Ardmore	Antlers
Beloit	Conway
Clinton	Dequeen
Enid	Fly Gap Mountain
Fort Smith	McAlester
Great Bend	Mena
Harrison	Mountain View
Helena	Russellville
Hutchinson	
Jefferson City	
Joplin	
Kansas City	
Lawrence	
Lawton	
Little Rock	
Manhattan	
Memphis	
Moberly	
Oklahoma City	
Poplar Bluff	
Pratt	
Quincy	
Rolla	
Springfield	
St. Louis	
Tulsa	
Wichita	
Woodward	

TABLE C-2. TERRAIN DATA USED IN ANALYSIS

Ardmore-E
Ardmore-W
Beloit-E
Beloit-W
Clinton-E
Clinton-W
Enid-E
Enid-W
FortSmith-E
FortSmith-W
GreatBend-E
GreatBend-W
Harrison-E
Harrison-W
Helena-W
Hutchinson-E
Hutchinson-W
Jefferson_City-E
Jefferson_City-W
Joplin-E
Joplin-W
Kansas_City-E
Kansas_City-W
Lawrence-E
Lawrence-W
Lawton-E
Lawton-W
LittleRock-E
LittleRock-W
Manhattan-E
Manhattan-W
Mcalester-E
Mcalester-W
Memphis-W
Moberly-E
Moberly-W
OklahomaCity-E
OklahomaCity-W
Poplar_Bluff-W
Pratt-E
Pratt-W
Quincy-W
Rolla-W
Russellville-E
Russellville-W
Saint_Louis-W
Springfield-E
Springfield-W
Tulsa-E
Tulsa-W
Wichita-E
Wichita-W
Woodward-E
Woodward-W

TABLE D-1. LIST OF SURFACE METEOROLOGCAL STATIONS

Station ID	Name	ID	Latitude	Longitude	X (km)	Y (km)
72244	TYLER/POUNDS FLD	KTYR	32.35	-95.4	371.587	-184.785
13962	ABILENE REGIONAL AP	KABI	32.417	-99.683	-31.309	-184.980
13959	WACO REGIONAL AP	KACT	31.617	-97.233	201.010	-271.953
13984	CONCORDIA BLOSSER MUNI AP	KCNK	39.55	-97.65	145.670	608.842
72450	CHANUTE MARTIN JOHNSON AP	KCNU	37.667	-95.483	339.779	405.295
3945	COLUMBIA REGIONAL AIRPORT	KCOU	38.817	-92.217	616.771	549.227
3927	DALLAS-FORT WORTH INTL AP	KDFW	32.9	-97.017	218.011	-128.585
13989	EMPORIA MUNICIPAL AP	KEMP	38.333	-96.183	275.837	476.935
13964	FORT SMITH REGIONAL AP	KFSM	35.333	-94.367	451.322	151.049
72344	FAYETTEVILLE DRAKE FIELD	KFYV	36	-94.167	465.386	225.981
93986	HOBART MUNICIPAL AP	KHBR	35	-99.05	27.301	102.282
72341	MEMORIAL FLD	KHOT	34.467	-93.1	572.243	61.814
3928	WICHITA MID-CONTINENT AP	KICT	37.65	-97.433	168.512	398.200
72445	KIRKSVILLE REGIONAL AP	KIRK	40.1	-92.55	577.848	689.334
72349	JOPLIN MUNICIPAL AP	KJLN	37.15	-94.5	429.008	351.924
3947	KANSAS CITY INT'L ARPT	KMCI	39.3	-94.717	398.209	589.456
72455	MANHATTAN RGNL	KMHK	39.133	-96.667	231.189	564.465
93950	MCALESTER MUNICIPAL AP	KMLC	34.9	-95.783	324.946	97.220
72249	NACOGDOCHES (AWOS)	KOCH	31.583	-94.717	439.952	-267.268
13967	OKLAHOMA CITY WILL ROGERS WOR	KOKC	35.383	-97.6	158.463	146.240
13969	PONCA CITY MUNICIPAL AP	KPNC	36.733	-97.1	200.187	297.058
72258	COX FLD	KPRX	33.633	-95.45	361.036	-42.304
13995	SPRINGFIELD REGIONAL ARPT	KSGF	37.233	-93.383	527.118	366.736
13957	SHREVEPORT REGIONAL ARPT	KSHV	32.45	-93.817	519.713	-166.247
72458	SALINA MUNICIPAL AP	KSLN	38.817	-97.667	145.653	527.389
13966	WICHITA FALLS MUNICIPAL ARPT	KSPS	33.983	-98.5	78.361	-10.434
72449	ST JOSEPH ROSECRANS MEMORIAL	KSTJ	39.767	-94.9	380.065	640.548
13930	WHITEMAN AFB	KSZL	38.717	-93.55	502.346	530.306
13996	TOPEKA MUNICIPAL AP	KTOP	39.067	-95.633	320.534	560.134
13968	TULSA INTERNATIONAL AIRPORT	KTUL	36.2	-95.883	310.581	241.170
13977	TEXARKANA WEBB FIELD	KTXK	33.45	-94	496.288	-56.103
72352	ARDMORE	K1F0	34.15	-97.117	205.406	10.192

TABLE D-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS

Station ID	Name	ID	Latitude	Longitude	X (km)	Y (km)
3948	NORMAN, OK	KOUN	35.233	-97.47	170.562	129.807
3952	LITTLE ROCK, AR	KLZK	34.83	-92.27	645.107	107.361
3990	FT. WORTH, TX	KFWD	32.8	-97.3	191.81	-140.322
13957	SHREVEPORT, LA	KSHV	32.45	-93.817	519.713	-166.247
13995	SPRINGFIELD, MO	KSGF	37.233	-93.383	527.118	366.736
13996	TOPEKA, KS	KTOP	39.067	-95.633	320.534	560.134

TABLE D-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS

Station ID	Name	ID	Latitude	Longitude	X (km)	Y (km)
30130	ALUM FORK	ALUM	34.800	-92.850	592.573	100.264
30178	ANTOINE	ANTO	34.033	-93.417	546.292	11.848
30220	ARKADELPHIA 2 N	ARKA	34.150	-93.050	579.146	26.959
30764	BLAKELY MOUNTAIN DAM	BLAK	34.567	-93.200	562.385	72.271
30832	BOONEVILLE 3 SSE	BOON	35.100	-93.917	493.544	127.441
30900	BRIGGSVILLE	BRIG	34.933	-93.500	532.484	111.205
31152	CAMDEN 1	CAMD	33.600	-92.817	604.758	-32.605
31457	CLARKSVILLE 6 NE	CLAR	35.533	-93.400	537.41	178.286
31952	DE QUEEN DAM	DE Q	34.100	-94.367	458.524	14.232
32020	DIERKS DAM	DIER	34.150	-94.083	484.26	21.186
32544	FOREMAN	FORE	33.717	-94.383	459.215	-28.412
32574	FORT SMITH MU, OK	FORT	35.333	-94.367	451.35	151.087
34185	LEWISVILLE	LEWI	33.367	-93.567	537.001	-63.005
34548	MAGNOLIA 3 N	MAGN	33.333	-93.250	566.603	-64.87
34756	MENA	MENA	34.567	-94.267	464.947	66.513
35200	NIMROD DAM	NIMR	34.950	-93.167	562.663	114.971
35908	PRESCOTT	PRES	33.800	-93.383	550.983	-13.852
37048	TEXARKANA	TEXA	33.450	-94.000	496.288	-56.103
37488	WALDRON	WALD	34.900	-94.100	478.133	104.322
165874	MANSFIELD	MANS	32.033	-93.700	533.444	-211.938
166244	MINDEN	MIND	32.600	-93.300	567.151	-146.621
166582	NATCHITOCHES	NATC	31.767	-93.100	591.967	-238.055
167738	RED RIVER RSRCH STN	RED	32.417	-93.633	537.167	-168.933
168440	SHREVEPORT, LA	SHRE	32.467	-94.317	472.727	-166.999
340179	ALTUS IRIG RES STN	ALTU	34.583	-99.333	1.525	55.944
340292	ARDMORE	ARDM	34.167	-97.133	203.861	12.009
340670	BENGAL	BENG	34.850	-95.083	388.894	94.294
341437	CANEY	CANE	34.233	-96.217	287.894	21.785
341544	CARTER TOWER	CART	34.267	-94.783	419.327	30.813
341684	CHANDLER 1	CHAN	35.700	-96.883	222.432	182.873
341750	CHICKASHA EXP STN	CHIC	35.050	-97.917	130.348	108.775

Station ID	Name	ID	Latitude	Longitude	X (km)	Y (km)
342334	CUSTER CITY	CUST	35.650	-98.833	46.626	174.563
342654	DUNCAN AIRPORT	DUNC	34.483	-97.967	126.717	45.752
342849	ELK CITY	ELK	35.383	-99.400	-4.528	144.821
343281	FORT COBB	FORT	35.100	-98.433	83.311	113.749
343497	GEARY	GEAR	35.633	-98.317	93.27	173.092
344052	HENNEPIN 5 N	HENN	34.567	-97.350	183.003	56.015
344202	HOBART	HOBA	35.033	-99.083	24.257	105.976
344865	KINGSTON	KING	34.000	-96.733	241.149	-5.578
344975	LAKE EUFAULA	LAKE	35.283	-95.433	355.031	141.02
345108	LEHIGH	LEHI	34.467	-96.217	287.04	47.705
345463	MACKIE 4 NNW	MACK	35.750	-99.833	-43.561	185.653
345589	MARSHALL	MARS	36.150	-97.617	155.403	231.376
345664	MCALESTER MUNI AP	MCAL	34.883	-95.783	324.985	95.368
346130	MUSKOGEE	MUSK	35.767	-95.333	361.825	195.03
346620	OKARCHE	OKAR	35.717	-97.983	123.223	182.725
346638	OKEMAH	OKEM	35.433	-96.300	275.968	154.796
346661	OKLAHOMA CITY, OK	OKLA	35.383	-97.600	158.462	146.277
347705	ROFF 2 WNW	ROFF	34.633	-96.883	225.503	64.423
349023	TUSKAHOMA	TUSK	34.633	-95.283	371.705	69.443
349629	WICHITA MTN WL REF	WICH	34.733	-98.717	57.832	72.804
349724	WISTER	WIST	34.950	-94.700	423.264	107.027
349748	WOLF 4 N	WOLF	35.133	-96.667	243.74	120.487
410016	ABILENE MUN, TX	ABIL	32.417	-99.683	-31.34	-185.017
410926	BONITA 4 NW	BONI	33.833	-97.633	158.551	-25.995
411246	BURLESON	BURL	32.550	-97.317	190.846	-168.184
411698	CHILDRESS MUNI AP	CHIL	34.433	-100.283	-85.552	39.694
411773	CLARKSVILLE 1 W	CLAR	33.617	-95.017	401.207	-42.383
411921	COMMERCE	COMM	33.200	-95.933	318.041	-92.161
412086	CRANFILLS GAP	CRAN	31.767	-97.833	143.748	-256.356
412096	CRESSON	CRES	32.533	-97.617	162.725	-170.597
412131	CROSS PLAINS 2	CROS	32.133	-99.167	17.298	-216.619
412242	DALLAS-FORT WORTH/FORT. TX.	DALL	32.900	-97.017	218.043	-128.584
412244	DALLAS LOVE FIELD	DALL	32.850	-96.850	233.76	-133.752
412404	DENTON 2 SE	DENT	33.200	-97.100	209.467	-95.394
412715	EASTLAND	EAST	32.400	-98.817	50.155	-186.788
413133	FERRIS	FERR	32.517	-96.667	251.944	-170.383
413285	FORT WORTH WSFO	FORT	32.833	-97.300	191.73	-136.613
413415	GAINESVILLE	GAIN	33.633	-97.133	205.242	-47.275
413546	GILMER 2 W	GILM	32.733	-94.983	408.8	-140.429
413642	GORDONVILLE	GORD	33.800	-96.850	230.983	-28.097
413771	GROESBECK 2	GROE	31.533	-96.533	267.703	-279.557
414137	HICO	HICO	31.983	-98.033	124.459	-232.49

Station ID	Name	ID	Latitude	Longitude	X (km)	Y (km)
414257	HONEY GROVE	HONE	33.583	-95.900	319.597	-49.433
414520	JACKSBORO 1 NNE	JACK	33.233	-98.150	111.677	-93.458
414866	KOPPERL	KOPP	32.133	-97.483	176.115	-214.908
414972	LAKE BRIDGEPORT DAM	LAKE	33.217	-97.833	141.174	-94.891
415348	LONGVIEW TX.	LONG	32.350	-94.650	442.089	-181.578
415463	MABANK 4 SW	MABA	32.350	-96.117	304.197	-187.329
415957	MINERAL WELLS 1 SSW	MINE	32.783	-98.117	115.428	-143.496
415996	MOLINE	MOLI	31.400	-98.317	98.384	-297.856
416108	MOUNT PLEASANT	MOUN	33.167	-95.000	405.037	-92.321
416177	NACOGDOCHES	NACO	31.617	-94.650	446.124	-263.206
416210	NAVARRO MILLS DAM	NAVA	31.950	-96.700	250.573	-233.576
416270	NEW BOSTON	NEW	33.450	-94.417	457.673	-58.192
416335	NEW SUMMERFIELD 2 W	NEW	31.983	-95.133	398.467	-224.521
416757	PALESTINE 2 NE	PALE	31.783	-95.600	355.27	-248.642
416834	PAT MAYSE DAM	PAT	33.867	-95.517	353.821	-16.591
417066	PITTSBURG 5 S	PITT	32.933	-94.933	412.444	-117.974
417300	PROCTOR RESERVOIR	PROC	31.967	-98.500	80.365	-234.849
417499	RED SPRINGS 2 ESE	RED	33.600	-99.383	-3.088	-53.373
417556	RENO	RENO	32.950	-97.567	166.549	-124.131
418047	SANTA ANNA	SANT	31.750	-99.333	1.58	-259.359
418583	STAMFORD 1	STAM	32.933	-99.800	-42.038	-127.448
418623	STEPHENVILLE 1 N	STEP	32.250	-98.200	108.347	-202.983
418743	SULPHUR SPRINGS	SULP	33.150	-95.633	346.171	-96.673
418778	SWAN	SWAN	32.450	-95.417	369.56	-173.721
419163	TRUSCOTT	TRUS	33.750	-99.867	-47.772	-36.562
419419	WACOMADISON-COOPER TX.	WACO	31.617	-97.233	200.979	-271.99
419532	WEATHERFORD	WEAT	32.750	-97.767	148.243	-146.722
419565	WELLINGTON	WELL	34.833	-100.217	-79.036	84.082
419715	WHITNEY DAM	WHIT	31.850	-97.367	187.779	-246.255
419729	WICHITA FALLS/SHEPS AFB TX	WICH	33.983	-98.500	78.36	-10.397
419817	WINCHELL	WINC	31.467	-99.167	17.441	-290.937
419893	WOODSON	WOOD	33.017	-99.050	27.996	-118.228
419916	WRIGHT PATMAN	WRIG	33.300	-94.167	481.752	-73.621
33165	HARRISON BOONE CNTY AP	HARR	36.267	-93.157	554.062	260.951
35228	NORFORK DAM	NORF	36.249	-92.256	634.629	264.668
140326	ARLINGTON	ARLI	37.900	-98.267	94.889	424.802
141233	CALDWELL	CALD	37.034	-97.616	153.714	329.468
141427	CHANUTE FAA AIRPORT	CHAN	37.670	-95.484	339.661	405.655
141767	CONCORDIA BLOSSER MUNI	CONC	39.551	-97.651	145.595	608.996
141867	COUNCIL GROVE LAKE	COUN	38.675	-96.526	244.858	513.992
143997	IONIA	IONI	39.661	-98.348	85.704	620.341
144341	KIOWA	KIOW	37.017	-98.485	76.705	326.534

Station ID	Name	ID	Latitude	Longitude	X (km)	Y (km)
145063	MARYSVILLE	MARY	39.833	-96.633	231.897	642.307
145306	MILFORD LAKE	MILF	39.075	-96.898	211.451	557.455
147160	SALINA AP	SALI	38.817	-97.667	145.653	527.389
148167	TOPEKA BILLARD MUNI AP	TOPE	39.069	-95.639	320.018	560.323
148293	UNIONTOWN	UNIO	37.848	-94.978	383.243	427.269
148830	WICHITA	WICH	37.650	-97.433	168.512	398.2
230204	APPLETON CITY	APPL	38.184	-94.026	464.443	468.749
230789	BOLIVAR 1 NE	BOLI	37.617	-93.391	523.736	409.205
231383	CASSVILLE RANGER STN	CASS	36.673	-93.858	488.813	302.115
231791	COLUMBIA REGIONAL AP	COLU	38.817	-92.218	616.657	549.212
232302	DORA	DORA	36.780	-92.233	632.313	323.535
234315	JOPLIN REGIONAL AP	JOPL	37.147	-94.502	428.83	351.544
234358	KANSAS CITY AP	KANS	39.300	-94.717	398.209	589.456
234544	KIRKSVILLE	KIRK	40.200	-92.567	575.614	700.322
234825	LEBANON 2 W	LEBA	37.685	-92.694	584.416	420.837
235834	MOUNTAIN GROVE 2 N	MOUN	37.153	-92.264	626.498	364.635
235987	NEVADA WATER PLANT	NEVA	37.839	-94.373	436.201	428.946
237976	SPRINGFIELD REG AP	SPRI	37.240	-93.390	526.478	367.443
238252	TABLE ROCK DAM	TABL	36.597	-93.308	538.258	296.711
238466	TRUMAN DAM & RESERVIOR	TRUM	38.258	-93.399	518.603	480.243
340215	AMES	AMES	36.250	-98.183	104.495	241.705
347196	PONCA CITY	PONC	36.717	-97.100	200.229	295.282
348992	TULSA INTL AIRPORT	TULS	36.198	-95.888	310.16	240.97

BART Five Factor Analysis ▪ Westar Energy

Jeffrey Energy Center and Gordon Evans Energy Center

Version 0

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1. EXECUTIVE SUMMARY

This report documents the determination of the Best Available Retrofit Technology (BART) as proposed by Westar Energy (Westar) for the Jeffrey Energy Center (JEC) located in St. Mary's, Kansas and the Gordon Evans Energy Center (GEEC) located in Colwich, Kansas. There are two units at JEC and one unit at GEEC that are subject to BART. JEC Unit 1 and Unit 2 are each coal-fired boilers with heat input ratings of 8,110 million British thermal units per hour (MMBtu/hr). GEEC Unit 2 is an oil-fired boiler with a heat input rating of 4,110 MMBtu/hr.

Westar has determined that JEC Unit 1 and Unit 2 and GEEC Unit 2 contribute greater than 0.5 delta deciviews (Δdv) to visibility impairment in a federally protected Class I area when compared to a natural background. Therefore, these three units are subject to BART. A summary of the visibility impairment attributable to the JEC Unit 1 and Unit 2 and GEEC Unit 2 is provided in Table 1-1.

TABLE 1-1. EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO JEC UNIT 1 AND UNIT 2 AND GEEC UNIT 2 (2001-2003)

	Wichita Mountains		Hercules Glades Wilderness		Caney Creek Wilderness		Mingo NWR		Upper Buffalo Wilderness	
	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98^{th} % Δdv	Days > 0.5 Δdv
JEC Unit 1 and Unit 2	0.99	59	0.90	63	0.73	37	0.49	21	0.85	53
GEEC Unit 2	1.08	85	0.40	16	0.38	14	0.17	4	0.42	16

Westar used the U.S. Environmental Protection Agency's (EPA's) guidelines[1] in 40 CFR Part 51 to determine BART for JEC Unit 1 and Unit 2 and GEEC Unit 2. Specifically, Westar conducted a five-step analysis to determine BART for SO_2, NO_X, and PM_{10} that included the following:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and document the results;
5. Evaluating visibility impacts

Based on the five-step analysis, Westar proposes the following as BART:

JEC Unit 1:

- PM_{10} – Westar proposes upgrades to the existing electrostatic precipitator (ESP).
- NO_X – Westar proposes to meet a BART limit of 0.15 lb/MMBtu by installing a low-NO_X burner (LNB) system.
- SO_2 – Westar proposes to meet a BART limit of 0.15 lb/MMBtu by rebuilding the existing wet scrubber.

1 40 CFR 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations

JEC Unit 2:

- PM_{10} – Westar proposes upgrades to the existing ESP.
- NO_X – Westar proposes to meet a BART limit of 0.15 lb/MMBtu by installing a LNB system.
- SO_2 – Westar proposes to meet a BART limit of 0.15 lb/MMBtu by rebuilding the existing wet scrubber.

GEEC Unit 2:

- PM_{10} – Westar proposes that no additional PM_{10} controls, other than the fuel switching from No.6 fuel oil to natural gas proposed as a BART alternative, are required for PM_{10} BART compliance. Additional PM controls for a gas-fired unit would provide little visibility improvement and require significant capital expenditures.
- NO_X and SO_2 – Westar proposes to meet the BART control requirement by switching from combusting No. 6 fuel oil to combusting natural gas, exclusively, except as discussed in Section 9 of this document.

The proposed BART control strategies will result in reductions of the visibility impacts attributable to JEC Unit 1 and Unit 2 and GEEC Unit 2. A summary of the visibility improvement based on the existing emission rates and proposed BART emission rates for JEC Unit 1 and Unit 2 is provided in Table 1-2. A summary of the visibility improvement based on the existing emission rates for GEEC Unit 2 and the BART control strategy for GEEC Unit 2 is provided in Table 1-3.

TABLE 1-2. VISIBILITY IMPAIRMENT IMPROVEMENT FROM JEC UNIT 1 AND UNIT 2 (2001-2003)

	Caney Creek Wilderness			Hercules Glades Wilderness			Mingo NWR			Upper Buffalo Wilderness			Wichita Mountains		
	Existing	BART	Improvement	Existing	BART	Improvement	Existing	BART	Improvement	Existing	BART	Improvement	Existing	BART	Improvement
Max Impact (Δdv)	2.74	0.85	69%	2.70	0.75	72%	1.44	0.44	69%	2.73	0.84	69%	3.51	1.19	66%
98% Impact (Δdv)	0.73	0.23	70%	0.90	0.30	67%	0.49	0.16	69%	0.85	0.25	71%	0.99	0.32	68%
Days > 0.5	37	4	89%	63	4	94%	21	0	100%	53	3	94%	59	11	81%

TABLE 1-3. VISIBILITY IMPAIRMENT IMPROVEMENT FROM GEEC UNIT 2 (2001-2003)

	Caney Creek Wilderness			**Hercules Glades Wilderness**			**Mingo NWR**			**Upper Buffalo Wilderness**			**Wichita Mountains**		
	Existing	BART*	Improvement	Existing	BART*	Improvement	Existing	BART*	Improvement	Existing	BART*	Improvement	Existing	BART*	Improvement
Max Impact (Δdv)	1.07	0.49	54%	1.31	0.93	29%	0.71	0.49	31%	2.22	1.62	27%	2.16	1.66	23%
98% Impact (Δdv)	0.38	0.25	34%	0.4	0.21	48%	0.17	0.08	55%	0.42	0.28	33%	1.08	0.69	36%
Days > 0.5	14	0	100%	16	4	75%	4	0	100%	16	11	31%	85	44	48%

* Based on the BART alternative presented in Section 9

2. Introduction and Background

On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile visibility impacts from the source are greater than 0.5 delta deciviews (Δdv) when compared against a natural background. Air quality modeling is the tool that is used to determine a source's visibility impacts.

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *"…an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonable be anticipated to result from the use of such technology.*

Specifically, the BART rule states that a BART determination should address the following five statutory factors:

1. Existing controls
2. Cost of controls
3. Energy and non-air quality environmental impacts
4. Remaining useful life of the source
5. Degree of visibility improvement as a result of controls

Further, the BART rule indicates that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results;
5. Evaluate visibility impacts

A BART determination should be made for each visibility affecting pollutant (VAP) by following the five steps listed above for each VAP.

Westar performed a BART applicability analysis for JEC Unit 1 and Unit 2 and GEEC Unit 2 and determined the units are subject to BART. The details of the applicability determination can be found in Section 3. Subsequently, Westar performed an analysis to determine BART for each VAP for JEC Unit 1 and Unit 2 and GEEC Unit 2. The VAPs emitted by JEC Unit 1 and Unit 2 and GEEC Unit 2 include NO_x, SO_2, and particulate matter with a mass mean diameter smaller than ten microns (PM_{10}) of various forms (filterable coarse particulate matter [PM_c], filterable fine particle matter [PM_f], elemental carbon [EC], inorganic condensable particulate matter [IOR CPM] as sulfates [SO_4], and organic condensable particulate matter [OR CPM] also referred to as secondary organic aerosols [SOA]). The BART determinations for SO_2, NO_X, and PM_{10} can be found in Sections 4, 5, and 6, respectively.

EPA established presumptive limits in the BART guidelines for coal-fired electric generating units (EGUs). The presumptive limits were established by reviewing BART-eligible units and determining a level of emissions reductions that would be cost effective. The EPA's BART guidelines state the following with regard to presumptive BART for coal-fired EGU units for SO_2:

> *"You must require 750 MW power plants to meet specific control levels for SO_2 of either 95 percent control or 0.15 lb/MMBtu… For coal fired EGUs with an existing post combustion SO_2 controls achieving less than 50 percent removal efficiencies, we recommend that you evaluate construction a new FGD system to meet the same emission limit as above (95 percent removal or 0.15 lb/MMBtu)"*

For power plants greater than 750 MW, EPA requires that state agencies apply the presumptive BART limit as a floor for SO_2. Thus, the SO_2 presumptive limit for both JEC Unit 1 and Unit 2 is 0.15 lb/MMBtu.

Similarly, the guidelines provide presumptive NO_X limits for coal-fired EGUs. JEC Unit 1 and Unit 2 are tangential-fired units burning sub-bituminous coal; the guidelines state that the NO_X presumptive limit is 0.15 lb/MMBtu for this type of EGU.

The BART guidelines state the following with regard to presumptive BART controls for oil-fired boilers:

"For oil-fired and gas-fired EGUs larger than 200 MW, we believe that installation of current combustion control technology to control NO_X is generally highly cost-effective and should be considered in your determination of BART for these sources."

EPA also established presumptive SO_2 controls for oil-fired EGUs. For oil-fired units, the guidelines state that sources of all sizes should evaluate limiting the sulfur content of the fuel oil to 1 percent or less by weight as BART. Thus, the SO_2 presumptive limit for GEEC Unit 2 is fuel oil sulfur content of 1 percent.

The BART guidelines do not specify presumptive BART limits for PM_{10} emissions.

As stated in Section 2, a BART-eligible source is subject-to-BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile of the visibility impacts from the source is greater than 0.5 Δdv when compared against a natural background. Westar conducted air quality modeling to predict the existing visibility impairment attributable to JEC Unit 1 and Unit 2 and GEEC Unit 2 in the following Class I areas:

- Wichita Mountains
- Hercules Glades Wilderness
- Upper Buffalo Wilderness
- Caney Creek Wilderness
- Mingo National Wildlife Refuge (NWR)

The modeling methods and procedures that were followed were provided to the Kansas Department of Health and Environment (KDHE) in a modeling protocol in September 2006. Table 3-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions. The SO_2 and NO_x emission rates are the highest actual 24-hour emission rates based on 2002-2004 continuous emissions monitoring system (CEMS) data. The PM_{10} emission rates are the calculated highest emission rates based on fuel data from 2002-2004 and AP-42 emission factors. The total PM_{10} emission rates include both the filterable and condensable fractions and are speciated into the following:

- Coarse particulate matter (PM_C)
- Fine particulate matter (PM_f)
- Sulfates (SO_4)
- Secondary organic aerosols (SOA)
- Elemental carbon (EC)

TABLE 3-1. EXISTING MAXIMUM 24-HOUR SO_2, NO_X, AND PM_{10} EMISSIONS (AS HOURLY EQUIVALENTS)

	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
JEC Unit 1	6,938.9	3,972.3	327.4	181.9	55.6	42.8	45.5	1.6
JEC Unit 2	7,128.2	3,924.0	303.9	168.8	51.6	39.8	42.2	1.5
GEEC Unit 2	5,766.7	4,818.3	431.5	38.7	104.7	260.5	6.8	20.8

Table 3-2 summarizes the stack parameters that were used to model JEC Unit 1 and Unit 2 and GEEC Unit 2 (two stacks). It should be noted that the good engineering practice (GEP) stack heights were modeled instead of the actual stack heights for JEC Unit 1 and Unit 2 since the GEP stack heights are less than the actual stack heights.

TABLE 3-2. SUMMARY OF EXISTING STACK PARAMETERS

	JEC Unit 1	JEC Unit 2	GEEC Unit 2 (Stack 2A)	GEEC Unit 2 (Stack 2B)
Latitude (degrees)	39.287	39.287	37.793	37.793
Longitude (degrees)	96.116	96.116	97.518	97.518
Actual Stack height (ft)	600	600	197	197
GEP Stack height (ft)	574	574	381	381
Stack Diameter (ft)	26	26	13	13
Exhaust Velocity (ft/s)	91.3	91.3	69	69
Exhaust Temperature (F)	300	300	290	290

The results of the modeling are summarized in Table 3-3. The results of the modeling indicate that the 98th percentile of the visibility impacts attributable to JEC Unit 1 and Unit 2 and GEEC Unit 2 are greater than 0.5 Δdv when compared against a natural background. Since the visibility impacts are greater than 0.5 Δdv, JEC Unit 1 and Unit 2 and GEEC Unit 2 are subject to BART.

TABLE 3-3. EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO JEC UNIT 1 AND UNIT 2 AND GEEC UNIT 2 (2001-2003)

Class I Area	Wichita Mountains		Hercules Glades Wilderness		Caney Creek Wilderness		Mingo NWR		Upper Buffalo Wilderness	
	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv
JEC Unit 1 and Unit 2	0.99	59	0.90	63	0.73	37	0.49	21	0.85	53
GEEC Unit 2	1.08	85	0.40	16	0.38	14	0.17	4	0.42	16

Tables 3-4 and 3-5 provide a breakdown of the visibility impacts listed in Table 3-3 by each VAP for JEC and GEEC, respectively.

TABLE 3-4. BREAKDOWN OF POLLUTANT SPECIFIC CONTRIBUTIONS TO EXISTING VISIBILITY IMPAIRMENT FOR JEC UNIT 1 AND UNIT 2 (2001-2003)

Class I Area	Visibility Impairment Attributable to SO_4 (%)	Visibility Impairment Attributable to NO_3 (%)	Visibility Impairment Attributable to SOA (%)	Visibility Impairment Attributable to EC (%)	Visibility Impairment Attributable to PM_c (%)	Visibility Impairment Attributable to PM_f (%)	Total Visibility Impairment 98% (Δdv)
Wichita Mountains Wilderness	51.13	48.28	0.44	0.04	0.01	0.1	0.99
Hercules Glades Wilderness	38.21	60.92	0.63	0.06	0.03	0.15	0.90
Caney Creek Wilderness	40.79	57.87	0.98	0.09	0.05	0.23	0.73
Mingo Wildlife	43.81	55.53	0.49	0.04	0.01	0.11	0.49
Upper Buffalo Wilderness	39.6	59.22	0.85	0.08	0.05	0.2	0.85

TABLE 3-5. BREAKDOWN OF POLLUTANT SPECIFIC CONTRIBUTIONS TO EXISTING VISIBILITY IMPAIRMENT FOR GEEC UNIT 2 (2001-2003)

Class I Area	Visibility Impairment Attributable to SO_4 (%)	Visibility Impairment Attributable to NO_3 (%)	Visibility Impairment Attributable to SOA (%)	Visibility Impairment Attributable to EC (%)	Visibility Impairment Attributable to PM_c (%)	Visibility Impairment Attributable to PM_f (%)	Total Visibility Impairment 98% (Δdv)
Wichita Mountains Wilderness	29.29	67.54	0.16	1.25	0.19	1.57	1.08
Hercules Glades Wilderness	41.15	57.14	0.09	0.7	0.04	0.88	0.40
Caney Creek Wilderness	26.11	71.72	0.12	0.89	0.04	1.11	0.38
Mingo Wildlife	63.14	34.96	0.1	0.78	0.03	0.98	0.17
Upper Buffalo Wilderness	35.67	62.6	0.09	0.71	0.02	0.89	0.42

As shown in Tables 3-4 and 3-5, the most significant contributors to the visibility impairment are sulfates (SO_4) and nitrates (NO_3). The SO_4 contribution is primarily from the chemical conversion of SO_2 emitted by JEC Unit 1 and Unit 2 and GEEC Unit 2 to SO_4; a very small fraction is from SO_4 emitted as condensable particulate. The NO_3 contribution is entirely from the chemical conversion of NO_X emitted from JEC Unit 1 and Unit 2 and GEEC Unit 2. The contribution of PM_{10} to the total visibility impairment can be estimated as the sum of the contributions from SOA, EC, PM_c, and PM_f. The PM_{10} contribution is less than the contribution from SO_2 and NO_X.

The existing maximum 24-hour SO_2 emission rates that were modeled for the BART applicability determination are summarized in Table 4-1.

TABLE 4-1. EXISTING MAXIMUM 24-HOUR SO_2 EMISSION RATES FOR JEC UNIT 1 AND UNIT 2

	Heat Input (MMBtu/hr)	SO_2 24-Hour Emission Rate (ton/24-hr)	SO_2 Hourly Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)
JEC Unit 1	8,110	83.3	6,938.9	0.86
JEC Unit 2	8,110	85.5	7,128.2	0.88

4.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES

Step 1 of the BART determination is the identification of all available retrofit SO_2 control technologies. A list of control technologies was obtained by reviewing the U.S. EPA's Clean Air Technology Center, control equipment vendor information, publicly-available air permits, applications, and technical literature published by the U.S. EPA and Regional Planning Organizations (RPOs).

The available retrofit SO_2 control technologies are summarized in Table 4-2 for JEC Unit 1 and 2.

TABLE 4-2. AVAILABLE SO_2 CONTROL TECHNOLOGIES FOR JEC UNIT 1 AND UNIT 2

SO_2 Control Technologies
Dry Sorbent Injection Spray Dryer Absorber (SDA) i.e., Semi-Dry Scrubber Wet Scrubber Circulating Dry Scrubber (CDS)

All of the technologies listed in Table 4-2 involve removing the SO_2 in the exhaust gas, which is known as flue gas desulfurization (FGD).

4.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

4.2.1 DRY SORBENT INJECTION

Dry sorbent injection involves the injection of a lime or limestone powder into the exhaust gas stream where SO_2 becomes entrained in the lime. The stream is then passed through a fabric filter to remove the sorbent and entrained SO_2. The process was developed as a lower cost FGD option because the mixing of the SO_2 and lime occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time and gas stream temperature, sorbent injection control efficiency is typically between 40 and 60 percent.[2] This control is a technically feasible option for the control of SO_2 from JEC Unit 1 and Unit 2.

4.2.2 SPRAY DRYER ABSORPTION (SDA)

Spray dryer absorption is a semi-dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO_2 is absorbed by the slurry droplets. The absorption of the SO_2 leads to the formation of calcium sulfite and calcium sulfate within the droplets. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter. Existing spray dryer absorption control efficiencies range from 60 to 95 percent.[3] This control is a technically feasible option for the control of SO_2 from JEC Unit 1 and Unit 2.

4.2.3 WET SCRUBBER

Wet scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of lime or limestone in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device such as a fabric filter or an ESP to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. Similarly to the chemistry illustrated above for spray dryer absorption, the SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite and calcium sulfate. Wet lime scrubbing is capable of achieving 80-95 percent control.[4] This control is a technically feasible option for the control of SO_2 from JEC Unit 1 and Unit 2.

4.2.4 CIRCULATING DRY SCRUBBER (CDS)

In the circulating dry scrubbing process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle; the exhaust is mixed with water, hydrated lime, recycled flyash and CDS reaction products. The intensive gas-solid mixing that occurs in the reactor promotes the reaction of sulfur oxides in the flue gas with the dry lime particles. The mixture of reaction products (calcium sulfite/sulfate), unreacted lime, and fly ash is carried out with the exhaust and collected in an ESP or fabric filter. A large portion of the collected particles is recycled to the reactor to sustain the bed and improve lime utilization. CDS absorbers have been installed with both fabric filters and ESPs for particulate control. The control efficiency of a CDS is similar to that of an SDA. This control is a technically feasible option for the control of SO_2 from JEC Unit 1 and Unit 2.

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[2] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005.

[3] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

[4] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

4.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 4-3 provides a ranking of the control efficiencies for the controls listed in the previous section for JEC Unit 1 and 2.

TABLE 4-3. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE SO_2 CONTROL TECHNOLOGIES FOR JEC UNIT 1 AND UNIT 2

Control Technology	Estimated Control Efficiency
Wet Scrubber	~80-95%
Spray Dryer Absorber (SDA)	~60-95%
Circulating Dry Scrubber (CDS)	~60-95%
Dry Sorbent Injection	~40-60%

Since dry sorbent injection has the lowest control level of the controls listed in Table 4-3, this control will no longer be evaluated.

4.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

Step four for the BART analysis procedure is the impact analysis. The BART determination guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

4.4.1 COST OF COMPLIANCE

The three remaining SO_2 control options (wet scrubbers, SDA, CDS) for JEC Unit 1 and Unit 2 are FGD systems capable of achieving similar maximum levels of SO_2 reductions. Westar will only evaluate wet scrubbers for BART. Since this control option achieves an equally high level of control as the other control options, cost analyses are not necessary.

4.4.2 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS

FGD systems require electricity to operate the ancillary equipment. Additionally, wet FGD systems generate wastewater and sludge that must be treated. This places additional burdens on the wastewater treatment and solid waste management capabilities. If wet scrubbing produces calcium sulfite sludge, the sludge will be water-laden, and it must be stabilized for landfilling. If wet scrubbing produces calcium sulfate sludge, it is stable and easy to dewater. However, control costs will be higher because additional equipment is required.

4.4.3 REMAINING USEFUL LIFE

The remaining useful life of JEC Unit 1 and Unit 2 does not impact the annualized capital costs because the useful lives of the units are anticipated to be at least as long as the capital cost recovery period, which is 20 years.

4.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS

A final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates of associated with a wet scrubber. The existing emission rates and emission rates associated with a wet scrubber were modeled using CALPUFF. The existing emission rates are the same rates that were modeled for the BART applicability analysis. The emission rate associated with the wet scrubber is 0.15 lb/MMBtu multiplied by the maximum hourly heat inputs for JEC Unit 1 and Unit 2. A sample calculation of the SO_2 emission rate associated with a wet scrubber for JEC Unit 1 is provided as follows:

$$P * HI = 1{,}216.5 \text{ lb/hr}$$

Where:
P (emission rate of wet scrubber) = 0.15 lb/MMBtu
HI (hourly heat input) = 8,110 MMBtu/hr

The existing hourly equivalent of the maximum 24-hour emission rates and the hourly equivalent of the 24-hour emission rates associated with the wet scrubber that were utilized in the visibility impact modeling are summarized in Table 4-4.

TABLE 4-4. SUMMARY OF EMISSION RATES MODELED IN SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR JEC UNIT 1 AND UNIT 2

Unit	Emission Rate Scenario	Emission Rate		
		SO_2 (lb/hr)	NO_X (lb/hr)	PM_{10}* (lb/hr)
JEC Unit 1	Existing Emission Rate	6,938.9	3,972.3	327.4
	Wet Scrubber	1,216.5	3,972.3	327.4
JEC Unit 2	Existing Emission Rate	7,128.2	3,924.0	303.9
	Wet Scrubber	1,216.5	3,924.0	303.9

*PM_{10} emissions are calculated based on AP-42 emission factors.

Comparisons of the existing visibility impacts and the visibility impacts based on the wet scrubber, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Tables 4-5 and 4-6 for JEC Unit 1 and JEC Unit 2, respectfully. The visibility improvement associated with the wet scrubber is also shown in Tables 4-5 and 4-6; this value was calculated as the difference between the existing visibility impairment and the visibility impairment for the wet scrubber as measured by the 98th percentile modeled visibility impact.

TABLE 4-5. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR JEC UNIT 1 (2001-2003)

	Wichita Mountains				Hercules Glades Wilderness				Caney Creek Wilderness				Mingo NWR				Upper Buffalo Wilderness			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing Emission Rate	1.91	0.51	24	-	1.44	0.47	19	-	1.46	0.37	11	-	0.75	0.25	5	-	1.45	0.43	17	-
Wet Scrubber	1.22	0.34	10	33%	0.78	0.30	6	36%	0.95	0.22	5	42%	0.48	0.16	0	34%	0.88	0.27	6	39%

*Improvement is based on the 98th percentile visibility impact (Δdv) of the wet scrubber over the existing emission rate.

TABLE 4-6. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR JEC UNIT 2 (2001-2003)

	Wichita Mountains				Hercules Glades Wilderness				Caney Creek Wilderness				Mingo NWR				Upper Buffalo Wilderness			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing Emission Rate	1.91	0.51	24	-	1.45	0.46	20	-	1.47	0.37	11	-	0.75	0.25	5	-	1.47	0.43	17	-
Wet Scrubber	1.20	0.33	10	34%	0.77	0.30	4	36%	0.93	0.21	5	43%	0.47	0.16	0	36%	0.87	0.26	6	40%

*Improvement is based on the 98th percentile visibility impact (Δdv) of a wet scrubber over the existing emission rate.

As shown in Table 4-5, the operation of a wet scrubber on JEC Unit 1 results in a 33 to 42 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to this unit. Similarly, as shown in Table 4-6, the operation of wet scrubbers on JEC Unit 2 results in a 34 to 43 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to this unit.

4.6 PROPOSED BART FOR SO_2

Westar has determined that the SO_2 BART emission rate for JEC Unit 1 and Unit 2 is 0.15 lb/MMBtu based on the operation of wet scrubbers. Westar is proposing to meet this limit for each unit on a 30-day rolling average, excluding periods of startup, shutdown and malfunction. Compliance will be demonstrated using data from the existing continuous emissions monitoring systems (CEMS).

5. JEC NO_X BART EVALUATION

The existing maximum daily NO_X emission rates that were modeled for the BART applicability determination are summarized in Table 5-1.

TABLE 5-1. EXISTING MAXIMUM 24-HOUR NO_X EMISSION RATE FOR JEC UNIT 1 AND UNIT 2

	Heat Input (MMBtu/hr)	NO_X 24-Hour Emission Rate (ton/24-hr)	NO_X Hourly Emission Rate (lb/hr)	NO_X Emission Rate (lb/MMBtu)
JEC Unit 1	8,110	47.7	3,972.3	0.49
JEC Unit 2	8,110	47.1	3,924.0	0.48

5.1 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

Step 1 of the BART determination is the identification of all available retrofit NO_X control technologies. A list of control technologies was obtained by reviewing the U.S. EPA's Clean Air Technology Center, control equipment vendor information, publicly-available air permits, applications, and technical literature published by the U.S. EPA and the RPOs.

The available retrofit NO_X control technologies are summarized in Table 5-2 for JEC Unit 1 and 2.

TABLE 5-2. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR JEC UNIT 1 AND UNIT 2

NO_X Control Technologies	
Combustion Controls	Flue Gas Recirculation (FGR) Overfire Air (OFA) Low NO_X Burners (LNB) and Ultra Low NO_X Burners (ULNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

NO_X emissions controls, as listed in Table 5-2, can be categorized as combustion or post-combustion controls. Combustion controls, including flue gas recirculation (FGR), overfire air (OFA), and Low NO_X Burners (LNB), reduce the peak flame temperature and excess air in the furnace which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) convert NO_X in the flue gas to molecular nitrogen and water.

5.2 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

5.2.1 COMBUSTION CONTROLS

5.2.1.1 FLUE GAS RECIRCULATION (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the heater or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces thermal NO_X formation. When operated without additional controls, the NO_X control efficiency range for FGR is 30 percent to 50 percent. When coupled with LNB the control efficiency increases to 50-72 percent.[5] This control is a technically feasible option for the control of NO_X from JEC Unit 1 and Unit 2.

5.2.1.2 OVERFIRE AIR (OFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed.

OFA as a single NO_X control technique may reduce NO_X emissions by 25 to 55 percent. When combined with LNB, reductions of up to 60 percent may result.[6] This control is a technically feasible option for the control of NO_X from JEC Unit 1 and Unit 2.

5.2.1.3 LOW AND ULTRA LOW NO_X BURNERS

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is limited by either one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_X formation. In the secondary zone, combustion

[5] "Midwest Regional Planning Organization Boiler Best Available Retrofit Technology (BART) Engineering Analysis" MACTEC, March 30, 2005.

[6] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005

products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_X formation. The estimated NO_X control efficiency for LNBs in high temperature applications is 25 percent. However when coupled with FGR or SNCR these efficiencies increase to 50-72 and 50-89 percent, respectively.[7]

ULNBs may incorporate a variety of techniques including induced FGR, steam injection, or a combination of techniques. These burners combine the benefits of flue gas recirculation and LNB control technologies. Rather than a system of fans and blowers (like FGR), the burner is designed to recirculate hot, oxygen depleted flue gas from the flame or firebox back into the combustion zone. This leads to a reduction in the average oxygen concentration in the flame without reducing the flame temperature below temperatures necessary for optimal combustion efficiency.

LNBs may also be coupled with neural net systems to further optimize combustion. Neural net systems are computer automated systems that measure certain operational parameters associated with combustion. Based on these measured parameters, the neural net systems can either automatically adjust operational parameters to achieve optimal operation or provide recommendations to operators of changes to boiler control elements. By accepting the recommendations, NO_X and unit heat rate can be optimized for best overall performance.

The estimated NO_X control efficiency for ULNBs in high temperature applications is 50 percent. Newer designs have yielded efficiencies of between 75-85 percent. When coupled with SCR, efficiencies in the range of 85-97 percent can be obtained.[8]

LNB systems are technically feasible for tangential and wall-fired boilers of various sizes, but are not feasible for other boiler types such as cyclone or stoker. [9] LNB systems are technically feasible for the control of NO_x from JEC Unit 1 and Unit 2.

5.2.2 Post Combustion Controls

5.2.2.1 Selective Catalytic Reduction

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed

[7] "Midwest Regional Planning Organization Boiler Best Available Retrofit Technology (BART) Engineering Analysis" MACTEC, March 30, 2005.

[8] Interim White Paper "Source Category: Electric Generating Units" Midwest RPO Candidate Control Measures, December 9, 2005

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selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions can be written:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. The NO_X control efficiency range for SCR is 70 to 90 percent.[10] This control is a technically feasible option for the control of NO_X from JEC Unit 1 and Unit 2.

5.2.2.2 SELECTIVE NON-CATALYTIC REDUCTION

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, because of higher stoichiometric ratios, both ammonia and urea SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_X reductions. The NO_X control efficiency range for SNCR is 25 to 50 percent.[11] This control is a technically feasible option for the control of NO_X from JEC Unit 1 and Unit 2.

5.3 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 5-3 provides a ranking of the NO_x control efficiencies for JEC Unit 1 and JEC Unit 2.

[10] Ibid.

[11] Interim White Paper "Source Category: Electric Generating Units" Midwest RPO Candidate Control Measures, December 9, 2005.

TABLE 5-3. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE NO_X CONTROL TECHNOLOGIES

Control Technology	Estimated Control Efficiency (%)
SCR	~70-90
LNB Systems	~30-60
FGR	~30-50
OFA	~25-55
LNB Only	~25-50
SNCR	~25-50

5.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step four for the BART analysis procedure is the impact analysis. The BART determination guidelines list four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

5.4.1 COST OF COMPLIANCE

The capital costs, operating costs, and cost effectiveness of LNB systems and SCR were estimated for the cost analysis. LNB systems refer to a control system which includes LNB and possibly OFA or neural net systems. These control options were included in the analysis because they provide the highest levels of control and are commonly used for NO_X control in large utility boilers.

<u>Control Costs</u>
The capital cost of the LNB systems for JEC Unit 1 and Unit 2 was estimated based on Westar's experience with the capital costs for a similar project on JEC Unit 3, and the operating costs were estimated using an EPA cost estimate method.[12] Westar is still experiencing what type of operating costs to expect from a LNB system project, but project specific data from which to base the annual operating costs over the operating life of the system does not yet exist, so an EPA estimate was relied upon.

The capital cost for the SCR was determined from recent SCR installation experience. The operating and maintenance costs for the SCR were estimated using an EPA cost method.[13] The EPA estimates for the operating and maintenance costs are considered to be study grade, which is +/- 30 percent accuracy.

[12] *Nitrogen Oxides (NO_X), Why and How They Are Controlled.* EPA 456/F-99-006R, November 1999.

[13] *Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-fired Boiler.* EPA 600/R-01/087, October 2001.

The capital costs were annualized over a 20-year period and then added to the annual operating costs to obtain the total annualized costs for each technology.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were estimated by subtracting the estimated controlled annual emission rates from the existing annual emission rates. The existing annual emission rates were the highest 365 day rolling totals as determined from CEMS data from 2002-2004.

The controlled annual emission rates were estimated based on NO_X emission rates of 0.15 lb/MMBtu for LNB systems and 0.10 lb/MMBtu for SCR. These emission rates were multiplied by the maximum hourly heat input (8,110 MMBtu/hr) and then multiplied by the annual number of operating hours. The annual number of operating hours was 8,760. The annual operating hours were based on the maximum number of annual operating hours of JEC Unit 1and Unit 2 from 2002-2004. The maximum annual operating time was approximately 94 percent for JEC Unit 1 and 96 percent for JEC Unit 2; therefore, an estimated 100 percent factor was used for both units. A sample of the controlled annual emission rate is shown as follows for a LNB system for JEC Unit 1:

$$0.15 lb / MMBtu * 8{,}110 MMBtu / hr * \frac{8{,}760 hrs}{yr} * \frac{ton}{2{,}000 lb} * 100\% = 5{,}220 \text{ tpy}$$

Cost Effectiveness

The cost effectiveness for the remaining two control options was determined by dividing the annual cost by the annual tons reduced. The incremental cost effectiveness was also calculated for the two control options. In this case, the incremental cost analysis was performed to show the incremental increase in costs between the SCR and the LNB system. The costs are summarized for JEC Unit 1 and JEC Unit 2 in Tables 5-4 and 5-5, respectively.

In the BART guidelines, EPA calculated that for all types of boilers other than cyclone boilers, combustion control technology is generally more cost-effective than post-combustion controls. EPA estimates that approximately 75 percent of the BART units (non-cyclone) could meet the presumptive NO_X limits at a cost of $100 to $1,000 per ton of NO_X removed based on the use of combustion control technology. For the units that could not meet the presumptive limits using combustion control technology, EPA estimates that almost all of these sources could meet the presumptive limits using advanced combustion controls; the EPA estimates that the cost of such controls are usually less than $1,500 per ton removed.

Tables 5-4 and 5-5 indicate that the cost effectiveness of LNB systems for JEC Unit 1 and Unit 2 is less than $1,500 per ton of NO_X removed. Tables 5-4 and 5-5 also indicate that the costs for SCR for JEC Unit 1 and Unit 2 are over $1500 per ton of NO_X removed (JEC Unit 1 SCR cost = $2,211/ton and JEC Unit 2 SCR cost = $1,738/ton). Additionally, the incremental costs of the SCR over the LNB systems are greater than $6,600 per ton of NO_X removed for JEC Unit 1 and Unit 2. Westar believes that the incremental costs are excessive.

TABLE 5-4. SUMMARY OF COST EFFECTIVENESS FOR JEC UNIT 1 NO_X CONTROLS

	Current Annual Emission Rate	Controlled Annual Emission Rate	Annual Emissions Reduced	Capital Cost	Annualized Capital Cost*	Annualized Fixed O&M*	Annualized Variable O&M*	Total Annualized Cost*	Cost Effectiveness	Incremental Cost
	(tpy)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)
LNB System	9,524	5,220†	4,304	11,500,000	1,350,790	506,709	0	1,857,499	432	-
SCR	9,524	3,480‡	6,044	81,000,000	9,514,260	338,492	3,510,068	13,362,820	2,211	6,613

*The costs are annualized in 2006 dollars.

†The LNB system represents an emission rate of 0.15 lb/MMBtu.

‡The SCR represents an emission rate of 0.1 lb/MMBtu.

TABLE 5-5. SUMMARY OF COST EFFECTIVENESS FOR JEC UNIT 2 NO_X CONTROLS

	Current Annual Emission Rate	Controlled Annual Emission Rate	Reduced Emissions	Capital Cost	Annualized Capital Cost*	Annualized Fixed O&M*	Annualized Variable O&M*	Total Annualized Cost*	Cost Effectiveness	Incremental Cost
	(tpy)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)
LNB System**	11,115	5,156†	5,959	11,500,000	1,350,790	506,709	0	1,857,499	312	-
SCR***	11,115	3,437‡	7,677	81,000,000	9,514,260	338,420	3,493,270	13,345,950	1,738	6,684

*The costs are annualized in 2006 dollars.

†The LNB w/ OFA emission rate represents an emission rate of 0.15 lb/MMBtu.

‡ The SCR represents an emission rate of 0.1 lb/MMBtu.

5.4.2 ENERGY IMPACTS & NON-AIR IMPACTS

SCR systems require electricity to operate the ancillary equipment. Additionally, the SCR can potentially cause significant environmental impacts related to the usage and storage of ammonia. Storage of aqueous ammonia above 10,000 lbs is regulated by a risk management program (RMP), since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. Ammonia can also be emitted in the exhaust of boilers that operate with SCR or SNCR for NO_X control due to ammonia slip.

Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_X, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution; which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

5.4.3 REMAINING USEFUL LIFE

The remaining useful life of JEC Unit 1 and Unit 2 do not impact the annualized capital costs of potential controls because the useful lives of the units are anticipated to be at least as long as the capital cost recovery period, which is 20 years.

5.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS

The final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with SCR and LNB systems. The existing emission rates and emission rates associated with SCR and LNB systems were modeled using CALPUFF. The existing emission rates are the same rates that were modeled for the BART applicability analysis. The emission rates associated with SCR and LNB systems for JEC Unit 1 and Unit 2 are the presumptive limit of 0.15 lb/MMBtu for LNB systems and 0.10 lb/MMBtu for SCR. These rates were multiplied by the maximum hourly heat inputs for JEC Unit 1 and Unit 2 to obtain the modeled hourly emission rate. A sample calculation of the NO_X emission rate associated with a LNB system for JEC Unit 1 is provided as follows:

$$E * HI = 1{,}216.5 \text{ lb/hr}$$

Where:
E (emission rate of LNB system) = 0.15 lb/MMBtu
HI (hourly heat input) = 8,110 MMBtu/hr

TABLE 5-6. SUMMARY OF EMISSION RATES MODELED IN NO_X CONTROL VISIBILITY IMPACT ANALYSIS FOR JEC UNIT 1 AND JEC UNIT 2

Unit	Emission Rate Scenario	Emission Rate		
		SO_2 (lb/hr)	NO_X (lb/hr)	PM_{10} (lb/hr)
JEC Unit 1	Existing Emission Rate	6,938.9	3,972.3	327.4
	LNB System	6,938.9	1,216.5	327.4
	SCR	6,938.9	811.0	327.4
JEC Unit 2	Existing Emission Rate	7,128.2	3,924.0	303.9
	LNB System	7,128.2	1,216.5	303.9
	SCR	7,128.2	811.0	303.9

Comparisons of the existing visibility impacts and the visibility impacts associated with SCR and LNB systems, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Tables 5-8 and 5-9 for JEC Unit 1 and JEC Unit 2, respectively. The visibility improvement associated with SCR and LNB systems are also shown in Tables 5-7 and 5-8; this value was calculated as the difference between the existing visibility impairment and the visibility impairment associated with SCR and LNB systems as measured by the 98th percentile modeled visibility impact.

TABLE 5-7. SUMMARY OF MODELED IMPACTS FROM NO_X CONTROL VISIBILITY IMPACT ANALYSIS FOR JEC UNIT 1 (2001-2003)

	Wichita Mountains				Hercules Glades Wilderness				Caney Creek Wilderness				Mingo NWR				Upper Buffalo Wilderness			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing Emission Rate	1.91	0.51	24	-	1.44	0.47	19	-	1.46	0.37	11	-	0.75	0.25	5	-	1.45	0.43	17	-
LNB System	1.34	0.34	11	33%	1.08	0.35	4	26%	1.04	0.25	6	33%	0.50	0.18	0	27%	1.23	0.32	4	25%
SCR	1.26	0.31	11	38%	1.03	0.32	4	31%	0.97	0.23	6	39%	0.46	0.18	0	30%	1.20	0.31	3	29%

*Improvement is based on the 98th percentile impact visibility impact (Δdv) of an LNB system and SCR over the existing emission rate.

TABLE 5-8. SUMMARY OF MODELED IMPACTS FROM NO_X CONTROL VISIBILITY IMPACT ANALYSIS FOR JEC UNIT 2 (2001-2003)

	Wichita Mountains				Hercules Glades Wilderness				Caney Creek Wilderness				Mingo NWR				Upper Buffalo Wilderness			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing Emission Rate	1.91	0.51	24	-	1.45	0.46	20	-	1.47	0.37	11	-	0.75	0.25	5	-	1.47	0.43	17	-
LNB System	1.36	0.34	11	32%	1.10	0.34	4	25%	1.05	0.25	6	32%	0.50	0.19	1	25%	1.24	0.33	4	23%
SCR	1.27	0.32	11	37%	1.04	0.33	4	28%	0.99	0.23	6	38%	0.47	0.18	0	29%	1.21	0.31	3	28%

*Improvement is based on the 98th percentile impact visibility impact (Δdv) of an LNB system and SCR over the existing emission rate.

As shown in Table 5-7, the installation of a LNB system on JEC Unit 1 results in a 25 to 33 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to this unit. The installation of SCR results in 29 to 39 percent visibility improvement. Similarly, as shown in Table 5-8, the installation of a LNB system on JEC Unit 2 results in a 23 to 32 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to this unit. The installation of SCR results in 28 to 38 percent visibility improvement. In short, the visibility improvement based on the installation of LNB systems for JEC Unit 1 and JEC Unit 2 is only slightly better than the visibility improvement based on the installation of SCR for the units. The slight increase in visibility improvement does not offset the large incremental cost of installing SCR over LNB systems.

5.6 PROPOSED BART FOR NO_X

Westar has determined that the NO_X BART emission rate is 0.15 lb/MMBtu for both JEC Unit 1 and Unit 2. Westar proposes to meet this limit for both JEC Unit 1 and Unit 2 by installing LNB systems. Westar has eliminated SCR as BART due to the high incremental cost of SCR over LNB systems and the minimal increase in visibility improvement.

The existing maximum 24-hour SO_2 emission rates that were modeled for the BART applicability determination are summarized in Table 6-1.

TABLE 6-1. EXISTING MAXIMUM 24-HOUR SO_2 EMISSION RATES

	Heat Input (MMBtu/hr)	SO_2 24-Hour Emission Rate (ton/24-hr)	SO_2 Hourly Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)
GEEC Unit 2	4,110	69.2	5,766.7	1.40

6.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES

Step 1 of the BART determination is the identification of all available retrofit SO_2 control technologies. A list of control technologies was obtained by reviewing the U.S. EPA's Clean Air Technology Center, control equipment vendor information, publicly-available air permits, applications, and technical literature published by the U.S. EPA and Regional Planning Organizations (RPOs).

The available retrofit SO_2 control technologies are summarized in Table 6-2 for GEEC Unit 2.

TABLE 6-2. AVAILABLE SO_2 CONTROL TECHNOLOGIES FOR GEEC UNIT 2

SO_2 Control Technologies
Dry Sorbent Injection
Spray Dryer Absorber (SDA) i.e., Semi-Dry Scrubber
Wet Scrubber
Circulating Dry Scrubber (CDS)
Fuel Switching

6.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

6.2.1 DRY SORBENT INJECTION, SPRAY DRYER ABSORPTION (SDA), WET SCRUBBER, CIRCULATING DRY SCRUBBER (CDS)

These technologies are collectively known as flue gas desulfurization (FGD) systems. FGD applications have not been used historically for SO_2 control in the U.S. electric industry on oil-fired units. As there are no known FGD applications for oil-fired units, the performance of FGDs on oil-fired units is unknown. EPA took this into account when evaluating the presumptive SO_2 emission rate[14] for oil-fired units and determined that the presumptive emission rate should be based on the sulfur content of the fuel oil, rather than on FGD. Therefore, FGDs are considered technically infeasible for the control of SO_2 from GEEC Unit 2 and will no longer be considered for BART.

6.2.2 Fuel Switching to One Percent Sulfur Fuel Oil

One percent sulfur fuel oil is listed by EPA as the presumptive BART limit for oil-fired units. The one percent sulfur oil is an alternative to the No. 6 fuel oil that is currently combusted by GEEC Unit 2. The lower sulfur content of the one percent sulfur fuel oil should result in approximately a 33 percent reduction in SO_2 emissions from GEEC Unit 2 as compared to the combustion of the current No. 6 fuel oil, which contains approximately 1.5 percent sulfur. Fuel switching to 1 percent sulfur fuel oil is a technically feasible option for the control of SO_2 from GEEC Unit 2.

6.3 Rank of Technically Feasible SO_2 Control Options by Effectiveness

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Fuel switching is the only remaining technically feasible control option GEEC Unit 2. Westar has estimated that switching to one percent sulfur oil, consistent with the EPA's presumptive BART determination for GEEC Unit 2, would result in approximately a 33% reduction in SO_2 emissions from GEEC Unit 2.

6.4 Evaluation of Impacts for Feasible SO_2 Controls

Step four for the BART analysis procedure is the impact analysis. The BART determination guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

6.4.1 Cost of Compliance

The cost effectiveness of switching to one percent sulfur fuel oil has been evaluated.

Control Cost

The cost of the fuel switching that was used in the cost effectiveness calculations was determined by calculating the cost of the current No. 6 fuel oil and determining the increased cost of switching to one percent sulfur fuel oil. It was assumed in this analysis that the fuel switch will not require any capital expenses. The fuel costs for 1 percent fuel oil was determined from the most recent fuel costs published by the Energy Information

[14] *Summary of Comments and Responses on the 2004 and 2001 Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations* EPA Docket Number OAR-2002-0076.

Administration. The fuel cost for the No. 6 fuel oil is the market price on February 14, 2007.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rates from the existing annual emission rates. The existing annual emission rates was the highest 365 day rolling totals as determined from CEMS data from 2002-2004. The controlled annual emission rate was estimated by reducing the existing annual emission rate by 33%.

Cost Effectiveness

In the BART guidelines, EPA calculated that that the majority of BART-eligible units could meet the presumptive limits at a cost of $400 to $2,000 per ton of SO_2 removed, based on the use of wet scrubbers and SDA systems. Table 6-3 indicates that the cost of switching to 1% sulfur fuel oil is well above this range.

TABLE 6-3. SUMMARY OF COST EFFECTIVENESS FOR SWITCHING FROM NO. 6 OIL TO 1% SULFUR FUEL OIL

Current/Uncontrolled Annual SO_2 Emission Rate	Controlled Annual SO_2 Emission Rate	Estimated Annual SO_2 Tons Reduced	Estimated SO_2 Control
(tpy)	(tpy)	(tpy)	(%)
4,303	2,869	1,434	33.33

Estimated No. 6 Oil Hourly Usage Rate*	Estimated No. 6 Oil Annual Fuel Usage†	No. 6 Oil Fuel Cost	Estimated Annual No. 6 Oil Fuel Cost	Estimated 1% S Fuel Oil Hourly Usage Rate*	Estimated 1% S Fuel Oil Annual Fuel Usage‡	1% S Fuel Oil Cost	Estimated Annual 1% S Fuel Oil Cost
Mgal/hr	Mgal/yr	Cents/gal	$/yr	Mgal/hr	Mgal/yr	Cents/gal	$/yr
27.40*	108,011†	85	91,809,180	27.96‡	110,215†	117.1	129,061,884

*4110 MMBtu/hr/150 MMBtu/Mgal

†Annual fuel usage is based on the hourly fuel usage rate and 3,942 annual operating hours (Assuming unit operates at an annual 45% capacity factor, 45% * 8,760 hours = 3,942 hours)

‡4110 MMBtu/hr/147 MMBtu/Mgal

Annual Cost of Fuel Switching	SO_2 Cost Effectiveness
($/yr)	($/ton)
37,252,704	25,969

6.4.1.1 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS

There are no energy or non-air quality impacts associated with fuel switching to one percent sulfur fuel oil.

6.4.1.2 REMAINING USEFUL LIFE

The remaining useful life of GEEC Unit 2 does not impact the annualized cost for this analysis, since it is assumed that fuel switching will not require any capital costs.

6.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS

A final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with the combustion of one percent sulfur fuel oil. The existing emission rate and emission rate associated with the combustion of one percent sulfur fuel oil were modeled using CALPUFF. The existing emission rates are the same rates that were modeled for the BART applicability analysis.

The SO_2 emission rate associated with the combustion of one percent sulfur fuel oil was calculated by scaling the hourly equivalent of the maximum 24-hour emission rate for GEEC Unit 2 by the ratio of the one percent sulfur fuel oil content and the current maximum sulfur content (1.5%). The calculation of the SO_2 emission rate for the one percent sulfur fuel oil for GEEC Unit 2 is provided as follows:

$$5{,}676 lb/hr * \frac{1\% Sulfur}{1.5\% Sulfur} = 3{,}845 \text{ lb/hr}$$

The existing hourly equivalent of the maximum 24-hour emission rates and the hourly equivalent of the 24-hour emission rates associated with the remaining control option that was utilized in the visibility impact modeling are summarized in Table 6-4.

TABLE 6-4. SUMMARY OF EMISSION RATES MODELED IN SO_2 CONTROL VISIBILITY IMPACT ANALYSIS

Unit	Emission Rate Scenario	Emission Rate		
		SO_2 (lb/hr)	NO_X (lb/hr)	PM_{10}* (lb/hr)
GEEC Unit 2	Existing Emission Rate	5,766.7	4,818.3	431.5
	1 Percent Sulfur Fuel Oil	3,844.5	4,818.3	326.3

*PM_{10} emissions are calculated based on AP-42 emission factors.

Comparisons of the existing visibility impacts and the visibility impacts associated with the combustion of one percent sulfur fuel oil, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Table 6-5 for GEEC Unit 2. The visibility improvement associated with the combustion of one percent sulfur fuel oil is also shown in Table 6-5;

this value was calculated as the difference between the existing visibility impairment and the visibility impairment for the remaining control option emission rates as measured by the 98th percentile modeled visibility impact.

TABLE 6-5. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR GEEC UNIT 2 (2001-2003)

	Wichita Mountains				Hercules Glades Wilderness				Caney Creek Wilderness				Mingo NWR				Upper Buffalo Wilderness			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing Emission Rate	2.16	1.08	85	-	1.31	0.40	16	-	1.07	0.38	14	-	0.71	0.17	4	-	2.22	0.42	16	-
One Percent Sulfur Fuel Oil	2.02	0.94	71	13%	1.19	0.34	10	13%	0.87	0.34	9	10%	0.65	0.14	2	16%	2.04	0.38	15	10%

*Improvement is based on the 98th percentile impact visibility impact (Δdv) of one percent sulfur fuel oil over the existing emission rate.

As shown in Table 6-5, the combustion of 1 percent sulfur fuel oil results in a 10 to 16 percent improvement (depending on the Class I area) to the existing visibility impairment attributable to GEEC Unit 2.

6.6 PROPOSED BART FOR SO_2

Westar has determined that SO_2 BART for GEEC Unit 2 is fuel switching to 1 percent sulfur fuel oil. However, Westar is proposing an alternative to BART for GEEC Unit 2. The alternative control for GEEC Unit 2 is natural gas combustion; the details of this alternative can be found in Section 9.

7. GEEC NO_X BART EVALUATION

The existing maximum daily NO_X emission rates that were modeled for the BART applicability determination are summarized in Table 7-1.

TABLE 7-1. EXISTING MAXIMUM 24-HOUR NO_X EMISSION RATE

	Heat Input (MMBtu/hr)	NO_X 24-Hour Emission Rate (ton/24-hr)	NO_X Hourly Emission Rate (lb/hr)	NO_X Emission Rate (lb/MMBtu)
GEEC Unit 2	4,110	57.8	4,818.3	1.17

7.1 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

Step 1 of the BART determination is the identification of all available retrofit NO_X control technologies. A list of control technologies was obtained by reviewing the U.S. EPA's Clean Air Technology Center, control equipment vendor information, publicly-available air permits, applications, and technical literature published by the U.S. EPA and the RPOs.

The available retrofit NO_X control technologies are summarized in Table 7-2 for GEEC Unit 2.

TABLE 7-2. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR GEEC UNIT 2

NO_X Control Technologies	
Combustion Controls	Flue Gas Recirculation (FGR) Overfire Air (OFA) Low NO_X Burners (LNB) and Ultra Low NO_X Burners (ULNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

NO_X emissions controls, as listed in Table 5-2, can be categorized as combustion or post-combustion controls. Combustion controls, including flue gas recirculation (FGR), overfire air (OFA), and Low NO_X Burners (LNB), reduce the peak flame temperature and excess air in the furnace which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) convert NO_X in the flue gas to molecular nitrogen and water.

7.2 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

7.2.1 COMBUSTION CONTROLS

7.2.1.1 FLUE GAS RECIRCULATION (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the heater or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces thermal NO_X formation. When operated without additional controls, the NO_X control efficiency range for FGR is 30 percent to 50 percent. When coupled with LNB the control efficiency increases to 50-72 percent.[15] This control is a technically feasible option for the control of NO_X from GEEC Unit 2.

7.2.1.2 OVERFIRE AIR (OFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed.

OFA as a single NO_X control technique may reduce NO_X emissions by 25 to 55 percent. When combined with LNB, reductions of up to 60 percent may result.[16] This control is a technically feasible option for the control of NO_X from GEEC Unit 2.

7.2.1.3 LOW AND ULTRA LOW NO_X BURNERS

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is limited by either one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_X formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_X formation. The estimated NO_X control efficiency for LNBs in high temperature applications is 25 percent.

[15] "Midwest Regional Planning Organization Boiler Best Available Retrofit Technology (BART) Engineering Analysis" MACTEC, March 30, 2005.

[16] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005

However when coupled with FGR or SNCR these efficiencies increase to 50-72 and 50-89 percent, respectively.[17]

ULNBs may incorporate a variety of techniques including induced FGR, steam injection, or a combination of techniques. These burners combine the benefits of flue gas recirculation and LNB control technologies. Rather than a system of fans and blowers (like FGR), the burner is designed to recirculate hot, oxygen depleted flue gas from the flame or firebox back into the combustion zone. This leads to a reduction in the average oxygen concentration in the flame without reducing the flame temperature below temperatures necessary for optimal combustion efficiency.

LNBs may also be coupled with neural net systems to further optimize combustion. Neural net systems are computer automated systems that measure certain operational parameters associated with combustion. Based on these measured parameters, the neural net systems can either automatically adjust operational parameters to achieve optimal operation or provide recommendations to operators of changes to boiler control elements. By accepting the recommendations, NO_X and unit heat rate can be optimized for best overall performance.

The estimated NO_X control efficiency for ULNBs in high temperature applications is 50 percent. Newer designs have yielded efficiencies of between 75-85 percent. When coupled with SCR, efficiencies in the range of 85-97 percent can be obtained.[18]

LNB systems are technically feasible for tangential and wall-fired boilers of various sizes, but are not feasible for other boiler types such as cyclone or stoker. [19] LNB systems are technically feasible for the control of NO_x from GEEC Unit 2.

7.2.2 Post Combustion Controls

7.2.2.1 Selective Catalytic Reduction

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions can be written:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

[17] "Midwest Regional Planning Organization Boiler Best Available Retrofit Technology (BART) Engineering Analysis" MACTEC, March 30, 2005.

[18] Interim White Paper "Source Category: Electric Generating Units" Midwest RPO Candidate Control Measures, December 9, 2005

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$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. The NO_X control efficiency range for SCR is 70 to 90 percent.[20] This control is a technically feasible option for the control of NO_X from GEEC Unit 2.

7.2.2.2 SELECTIVE NON-CATALYTIC REDUCTION

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, because of higher stoichiometric ratios, both ammonia and urea SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_X reductions. The NO_X control efficiency range for SNCR is 25 to 50 percent.[21] This control is a technically feasible option for the control of NO_X from GEEC Unit 2.

7.3 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 7-3 provides a ranking of the control efficiencies for the controls listed in the previous section for GEEC 2.

[20] Ibid.

[21] Interim White Paper "Source Category: Electric Generating Units" Midwest RPO Candidate Control Measures, December 9, 2005.

TABLE 7-3. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE NO_X CONTROL TECHNOLOGIES

Control Technology	Estimated Control Efficiency (%)
SCR	~70-90
LNB Systems	~30-60
FGR	~30-50
OFA	~25-55
LNB Only	~25-50
SNCR	~25-50

7.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step four for the BART analysis procedure is the impact analysis. The BART determination guidelines list four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

7.4.1 COST OF COMPLIANCE

As mentioned in Section 2 of this report, EPA has concluded that "for oil-fired and gas-fired EGUs larger than 200 MW, we believe that installation of current combustion control technology to control NO_X is generally highly cost-effective and should be considered in your determination of BART for these sources". Thus, Westar is proposing that BART for GEEC Unit 2 is the operation of LNB.

For purposes of this 5 factor analysis, the capital costs, operating costs, and cost effectiveness of an SCR have been estimated. This control option is the only control option included in the analysis because it provides the highest level of NO_x control and it is the only technology with control efficiency higher than that of LNB systems. Should the analysis conclude that SCR is not BART, the next best control to SCR is LNB, and this will be selected as BART.

<u>Control Costs</u>
The capital cost and operating costs of SCR were estimated based on recent SCR installation experience. The capital costs were annualized over a 20-year period and then added to the annual operating costs to obtain the total annualized costs.

<u>Annual Tons Reduced</u>
The annual tons reduced that were used in the cost effectiveness calculations were estimated by subtracting the estimated controlled annual emission rates from the existing

annual emission rates. The existing annual emission rates were the highest 365 day rolling totals as determined from CEMS data from 2002-2004.

The controlled annual emission rates were estimated by multiplying an estimated control efficiency for the SCR (90 percent) by the existing annual emission rates. A sample of the controlled annual emission rate is shown as follows:

$$2{,}352\,tpy * (100\% - 90\%) = 235 \text{ tpy}$$

<u>Cost Effectiveness</u>

The cost effectiveness for the SCR was determined by dividing the annual cost by the annual tons reduced. The cost is summarized in Table 7-4. The cost of the SCR is greater than $5,300/ton of NO_X removed. Westar believes this cost is excessive.

TABLE 7-4. SUMMARY OF COST EFFECTIVENESS FOR GEEC UNIT 2 NO_X CONTROLS

	Current Annual Emission Rate	Controlled Annual Emission Rate*	Estimated Reduced Emissions	Capital Cost†	Annualized Capital Cost‡	Annualized Fixed O&M‡	Annualized Variable O&M‡	Total Annualized Cost	Cost Effectiveness
	(tpy)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)
SCR	2,352	235	2,117	81,000,000	9,514,260	218,932	1,627,628	11,360,820	5,367

*The annual emission rate represents a control efficiency of 90%.

†The SCR capital cost was determined from recent SCR installation experience

‡The costs are annualized in 2006 dollars.

7.4.2 Energy Impacts & Non-Air Impacts

SCR systems require electricity to operate the ancillary equipment. Additionally, the SCR can potentially cause significant environmental impacts related to the usage and storage of ammonia. Storage of aqueous ammonia above 10,000 lbs is regulated by a risk management program (RMP), since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. Ammonia can also be emitted in the exhaust of boilers that operate with SCR or SNCR for NO_X control due to ammonia slip.

Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_X, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution; which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

7.4.3 Remaining Useful Life

The remaining useful life of GEEC Unit 2 does not impact the annualized capital costs of potential controls because the useful life of the unit is anticipated to be at least as long as the capital cost recovery period, which is 20 years.

7.5 Evaluation of Visibility Impact of Feasible NO_X Controls

The final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with SCR. The existing emission rates and emission rates associated with SCR were modeled using CALPUFF. The existing emission rates are the same rates that were modeled for the BART applicability analysis.

The emission rate associated with the SCR for GEEC Unit 2 is 0.12 lb/MMBtu. The emission rate for SCR was determined by reducing the existing hourly equivalent of the maximum 24-hour emission rate by a control efficiency of 90 percent.

The existing hourly equivalent of the maximum 24-hour emission rates and the hourly equivalent of the 24-hour emission rates associated with SCR are summarized in Table 7-5.

TABLE 7-5. SUMMARY OF EMISSION RATES MODELED IN NO_X CONTROL VISIBILITY IMPACT ANALYSIS

Unit	Emission Rate Scenario	Emission Rate		
		SO_2 (lb/hr)	NO_X (lb/hr)	PM_{10} (lb/hr)
GEEC Unit 2	Existing Emission Rate	5,766.7	4,818.3	431.5
	SCR	5,766.7	481.8	431.5

Comparisons of the existing visibility impacts and the visibility impacts associated with SCR, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Table 7-6 for GEEC Unit 2. The visibility improvement associated with SCR is also shown in Table 7-6; this value was calculated as the difference between the existing visibility impairment and the visibility impairment for the remaining control options as measured by the 98th percentile modeled visibility impact.

TABLE 7-6. SUMMARY OF MODELED IMPACTS FROM NO_X CONTROL VISIBILITY IMPACT ANALYSIS FOR GEEC UNIT 2 (2001-2003)

	Wichita Mountains				Hercules Glades Wilderness				Caney Creek Wilderness				Mingo NWR				Upper Buffalo Wilderness			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing Emission Rate	2.16	1.08	85	-	1.31	0.40	16	-	1.07	0.38	14	-	0.71	0.17	4	-	2.22	0.42	16	-
SCR	1.34	0.60	28	45%	1.09	0.20	5	51%	0.65	0.21	4	46%	0.34	0.09	0	48%	1.07	0.20	8	51%

*Improvement is based on the 98th percentile impact visibility impact (Δdv) of SCR over the existing emission rate.

As shown in Table 7-6, the installation of SCR results in 45 to 51 percent visibility improvement (depending on the Class I area) to the existing visibility impairment attributable to GEEC Unit 2. However, as documented in Table 7-4, the cost of SCR for this unit is estimated at over $5,300/ton. This large cost does not offset the visibility improvement that would be obtained by controlling NO_x using an SCR. Further, the future visibility impairment attributable to GEEC Unit 2 will be significantly improved from the existing visibility impairment based on the switch from the combustion of No. 6 fuel oil to the combustion of natural gas, and the large corresponding reduction in SO_2 emissions.

7.6 PROPOSED BART FOR NO_X

Since SCR is not cost effective for GEEC Unit 2, Westar has determined that NO_x BART for GEEC Unit 2 is a LNB. However, Westar is proposing an alternative to BART for GEEC Unit 2. The alternative control for GEEC Unit 2 is natural gas combustion; the details of this alternative can be found in Section 9.

The primary source of PM from JEC Unit 1 and Unit 2 is the fly ash in the flue gas. Other sources of PM include unburned carbon present in the flue gas, which is the result of incomplete combustion, and reactions of SO_2 and NO_X compounds to form fine PM in the form of nitrates, sulfur trioxide, and sulfates. PM emissions from JEC Unit 1 and Unit 2 are currently controlled by electrostatic precipitators (ESP). Similarly, PM emissions from GEEC Unit 2 are particles generated during the combustion of the No. 6 fuel oil. PM emissions from GEEC Unit 2 are currently uncontrolled.

The maximum daily PM_{10} emission rates that were modeled for the BART applicability determination are summarized in Table 8-1.

TABLE 8-1. EXISTING MAXIMUM 24-HOUR PM_{10} EMISSION RATE

	Heat Input (MMBtu/hr)	PM_{10} 24-Hr Emission Rate (ton/24-hr)	PM_{10} Hourly Emission Rate (lb/hr)	PM_{10} Emission Rate (lb/MMBtu)
JEC Unit 1	8,110	3.93	327.4	0.04
JEC Unit 2	8,110	3.65	303.9	0.04
GEEC Unit 2	4,110	5.2	431.5	0.10

From Table 8-1 it can be seen that the current PM_{10} emission rates for JEC Unit 1 and Unit 2 and GEEC Unit 2 are much less than the current emission rates of SO_2 and NO_X. The low PM_{10} emission rates correspond to low visibility impacts attributable to PM_{10} when compared to the impacts attributable to SO_2 and NO_X, from JEC Unit 1 and Unit 2 and GEEC Unit 2, as shown in Tables 8-2 and 8-3.

TABLE 8-2. VAP VISIBILITY IMPAIRMENT CONTRIBUTIONS FROM JEC UNIT 1 AND UNIT 2 (2001-2003)

	Visibility Impairment Attributable to SO_4[1] (%)	Visibility Impairment Attributable to NO_3[2] (%)	Visibility Impairment Attributable to PM_{10}[2] (%)
Wichita Mountains Wilderness	51.13	48.28	0.59
Hercules Glades Wilderness	38.21	60.92	0.87
Caney Creek Wilderness	40.79	57.87	1.35
Mingo Wildlife	43.81	55.53	0.65
Upper Buffalo Wilderness	39.6	59.22	1.18

1 The visibility impairment attributable to SO_4 is primarily from SO_2 emissions. A very small portion is from SO_4 emitted as condensable particulate.

2 The visibility impairment attributable to NO_3 is entirely from NO_X emissions.
3 The visibility impairment attributable to PM_{10} is the sum of the visibility impairment attributable to all modeled primary PM species (PMc, PMf, EC, and SOA).

TABLE 8-3. VISIBILITY IMPAIRMENT CONTRIBUTIONS FROM GEEC UNIT 2(2001-2003)

	Visibility Impairment Attributable to SO_4[1] (%)	Visibility Impairment Attributable to NO_3[2] (%)	Visibility Impairment Attributable to PM_{10}[2] (%)
Wichita Mountains Wilderness	29.29	67.54	3.17
Hercules Glades Wilderness	41.15	57.14	1.71
Caney Creek Wilderness	26.11	71.72	2.16
Mingo Wildlife	63.14	34.96	1.89
Upper Buffalo Wilderness	35.67	62.6	1.71

1 The visibility impairment attributable to SO_4 is primarily from SO_2 emissions. A very small portion is from SO_4 emitted as condensable particulate.

2 The visibility impairment attributable to NO_3 is entirely from NO_X emissions.

3 The visibility impairment attributable to PM_{10} is the sum of the visibility impairment attributable to all modeled primary PM species (PMc, PMf, EC, and SOA).

Westar proposes to upgrade the existing ESPs on JEC Unit 1 and Unit 2 in order to improve the PM control from these units. The upgrades to the existing ESPs will improve control of PM from JEC Unit 1 and Unit 2, thereby improving the visibility impacts from JEC Unit 1 and Unit 2.

Westar proposes that no additional PM control technologies are required for GEEC Unit 2, which is currently uncontrolled. The fuel switching from fuel oil no. 6 to natural gas proposed as a BART alternative for SO_2 (see Section 9) will significantly reduce the PM emissions from GEEC Unit 2. Given the small PM emission rates from natural gas combustion, Westar believes that the reduced PM emissions from the fuel switching combined with the cost of retrofitting GEEC Unit 2 with a new PM control technology would provide little visibility improvement and require significant capital expenditures.

9. PROPOSED GEEC BART ALTERNATIVE

Based on the GEEC SO_2 and NO_x BART analyses, Westar has determined that BART for SO_2 for GEEC Unit 2 is the combustion of 1 percent sulfur fuel oil and BART for NO_X is a LNB. Westar is proposing an alternative to the controls determined to meet BART for SO_2 and NO_X for GEEC Unit 2. In order for control strategies to be acceptable as an alternative to what is determined to meet BART, the alternatives must show greater visibility improvement than what is determined to meet BART based on the following visibility metrics:

- The maximum visibility impact
- The 98th percentile visibility impact
- The number of days where the visibility impacts are greater than 0.5 Δdv

In other words, the values for the metrics listed above for an alternative BART control strategy must be equal to or better than the values for the BART control strategy for each Class I area.

As an alternative to combusting 1 percent fuel oil to reduce SO_2 and LNB to reduce NO_X for GEEC Unit 2, Westar is proposing to combust natural gas in GEEC Unit 2. The switch to natural gas will provide greater than 95 percent SO_2 control from GEEC Unit 2.

9.1.1.1 COMPLIANCE WITH ALTERNATIVE BART CONTROL STRATEGY

Westar is proposing to demonstrate compliance with the alternative BART control strategy for GEEC Unit 2 that includes switching from No. 6 fuel oil to natural gas by submitting annual certifications of compliance verifying that natural gas was the only fuel combusted in GEEC Unit 2 for the year, except as provided below.

In order to assure electric system reliability, Westar requires the availability of an emergency fuel for backup, as well as the ability to burn a limited amount of the fuel periodically during non-emergencies to assure that the emergency system functions adequately. When the natural gas company implements an Operational Flow Order (OFO) or declares an emergency which could result in an impact to electric system reliability, Westar will combust No. 6 fuel oil for the time period of the emergency. Westar will diminish the existing supply of No. 6 fuel oil, once diminished the emergency fuel will be replaced with a fuel oil containing 1% or less sulfur content.

9.1.2 COMPARISON OF VISIBILITY IMPACTS FOR BART AND PROPOSED ALTERNATIVE BART CONTROL STRATEGIES

The modeled visibility impacts of the BART control strategy and the proposed alternative BART control strategy are summarized in Table 9-1. The visibility improvement associated with the BART and alternative BART control options are also shown in Table 9-1; this value was calculated as the difference between the existing visibility impairment and the visibility impairment for the BART and alternative BART control options as measured by the 98^{th} percentile modeled visibility impact. The visibility impacts for each metric are lower in all five Class I areas for the alternate BART control strategy.

TABLE 9-1. MODELED IMPACTS BASED ON PRESUMPTIVE BART EMISSION RATES AND ALTERNATIVE BART AT GEEC UNIT 2 (2001-2003)

	Wichita Mountains				Hercules Glades Wilderness				Caney Creek Wilderness				Mingo NWR				Upper Buffalo Wilderness			
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Visibility Improvement*
Existing	2.16	1.08	85	-	1.31	0.40	16	-	1.07	0.38	14	-	0.71	0.17	4	-	2.22	0.42	16	-
BART - LNB + 1% sulfur fuel oil	2.02	0.94	71	13%	1.19	0.34	10	13%	0.87	0.34	9	10%	0.65	0.14	2	16%	2.04	0.38	15	10%
Alternative - Natural gas	1.66	0.69	44	36%	0.93	0.21	4	48%	0.49	0.25	0	34%	0.49	0.08	0	55%	1.62	0.28	11	33%

Westar Energy.

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MAY 20 2009
Bureau of Air and Radiation

May 18, 2009

Mr. Andy Hawkins
Kansas Department of Health and Environment
Bureau of Air and Radiation
1000 SW Jackson, Suite 400
Topeka, Kansas 66612-1367

Dear Andy:

Enclosed please three CDs containing the Best Available Retrofit Technology (BART) updated modeling analysis and associated information which includes a revised Alternative BART Case for Gordon Evans Energy Center (GEEC) Unit 2 as well as supplemental modeling for the Presumptive BART Case reflecting two separate NO_x emission rate scenarios of 0.8 and 0.2 lb/mmBtu (pounds per million British Thermal Units) coupled with an SO2 emission rate equivalent to burning 1 percent sulfur fuel oil.

Per our discussion, it appears the modeling conducted for GEEC Unit 2 in support of the "Jeffrey Energy Center and Gordon Evans Energy Center BART Five Factor Analysis", dated August 2007, contained an hourly NO_x emission rate of 4,818 lb/hr for all three modeling scenarios including the existing Base Case, the Presumptive BART Case (1 percent sulfur fuel oil and low NO_x burners) and the Alternative BART Case (natural gas only). Based upon your feedback, there is concern regarding this analysis and the use of the same hourly NO_x emission rate for all modeling scenarios, as this hourly NO_x emission rate may not be reflective of the use of low NO_x burners on GEEC Unit 2. As a result of our discussions, Westar Energy, Inc. has reviewed the modeling analysis conducted and determined that other modeling scenarios with reduced hourly NO_x emission rates simulating the use of low NO_x burners were evaluated by Westar Energy, Inc. during the BART evaluation process, however, these scenarios were inadvertently omitted from the final BART Five Factor Analysis document.

The table below provides a summary of GEEC Unit 2's emission rates for the Presumptive BART Cases where the NO_x hourly emission rates equal 0.8 lb/mmBtu and 0.2 lb/mmBtu, and an updated Alternative BART case with an adjust hourly NO_x emission rate. The table also shows the maximum and 98th percentile visibility impacts for Wichita Mountains which is the Class I area with the highest modeled impacts resulting from the operation of GEEC Unit 2. The modeling results of the predicted visibility impacts on the other nearby Class I areas are included on an Excel spreadsheet contained on Disk 1 of the enclosed CDs.

	Presumptive BART Case 1% Sulfur, LNB at 0.8 lb/MMBtu (deciview)	Presumptive BART Case (1% Sulfur, LNB at 0.2 lb/MMBtu) (deciview)	Alternative BART Case (Natural Gas) (deciview)
Maximum	1.575	1.02	0.774
98%	0.804	0.474	0.334
NO_x (lb/hr)	3,288.0	822	2136
SO_2 (lb/hr)	3,844.4	3,844.4	1.70
PM_{10} (lb/hr)	324.7	326.3	30.6

As summarized in the table above, Westar Energy, Inc. assumed for the presumptive BART case which includes 1 percent sulfur fuel oil and the use of low NO_x burners, two separate hourly NO_x emission rates of 3,288 lb/hr and 822 lb/hr that equate to 0.8 lb/mmBtu and 0.2 lb/mmBtu, respectively. These hourly NO_x emission rates equate to a reduction of 32 percent and 83 percent, respectively, from the Base Case hourly NO_x emission rate of 4,818 lb/hr. Both modeling scenarios represent the range of emission reductions that may be achieved with the use of low NO_x burners on a typical boiler, with the 83 percent being on the high end of any expected NO_x control efficiency. GEEC Unit 2 would not be characterized as a typical boiler due to the Unit's small furnace size, short retention time and pressurization. As such, it is questionable if these high levels of NO_x control could be achieved in reality from GEEC Unit 2. However, for this analysis, it is assumed these levels of control are achievable and the modeling analyses have been conducted to reflect these levels of control.

Because the 2002 to 2004 BART baseline emission data period for GEEC Unit 2 did not contain any days with an entire 24-hour period of natural gas operation, Westar Energy, Inc., reviewed additional years of data beyond the 2002 to 2004 timeframe to develop a natural gas NO_x hourly emission rate. A review of the emission data from 2005 to present, indicated the highest natural gas emission rate for a complete 24-hour day occurred on July 31, 2006 and equated to an equivalent hourly NO_x emission rate of 1,909 lb/hr. As suggested by the Kansas Department of Health and Environment (KDHE), since this selected day is outside of the 2002 to 2004 BART baseline period, Westar Energy, Inc. compared the average hourly heat input for the day with the maximum 24-hour emissions from the 2002 to 2004 BART baseline data period (January 24, 2003, 4,818 lb/hr NO_x and 3,164 mmBtu/hr) to the average hourly heat input for the NO_x 24-hour maximum emission period of natural gas firing outside of the 2002 to 2004 BART baseline data period (July 31, 2006, 1,909 lb/hr NO_x and 2,828 mmBtu/hr). Since the day with the NO_x 24-hour maximum emission period of natural gas firing lies outside of the 2002 to 2004 BART baseline data period, the modeled natural gas NO_x hourly emission rate was increased by the ratio of 3,164 mmBtu/hr (the average hourly heat input on July 24, 2003) over 2,828 mmBtu/hr (the average hourly heat input on July 31, 2006) resulting in an hourly NO_x emission rate for the Alternative BART Case of 2,136 lb/hr (1,909 lb/hr x (3,164 mmBtu/hr/2,828 mmBtu)) in order to simulate the modeled impacts as though GEEC Unit 2 fired natural gas instead of fuel oil for the entire 24-hour period on the maximum NO_x 24-hour emission day of January 24, 2003.

As summarized in the table above, the Alternative BART Case has lower modeled visibility impacts than the two Presumptive BART Cases. In addition, the Alternative BART Case also has lower modeled visibility impacts than the SCR Case as described in Section 7 of the BART Five Factor Analysis Document. Because the Alternative BART Case of operating on natural gas only yields visibility improvement better than any of the other modeled Cases, Westar Energy, Inc. did not include or further evaluate the detailed costs or other issues associated with the installation of low NO_x burners on GEEC Unit 2. Therefore, based upon these additional modeling results, Westar Energy, Inc. continues to believe the Alternative BART Case yields greater visibility improvements than the Presumptive BART Case and KDHE should conclude the Alternative BART Case represents BART for GEEC Unit 2.

Should you have any questions regarding this additional modeling analysis, please do not hesitate to contact me at 785-575-1614.

Sincerely,

WESTAR ENERGY, INC.

Daniel R. Wilkus, P.E.
Manager, Air and Water Programs

Enclosures